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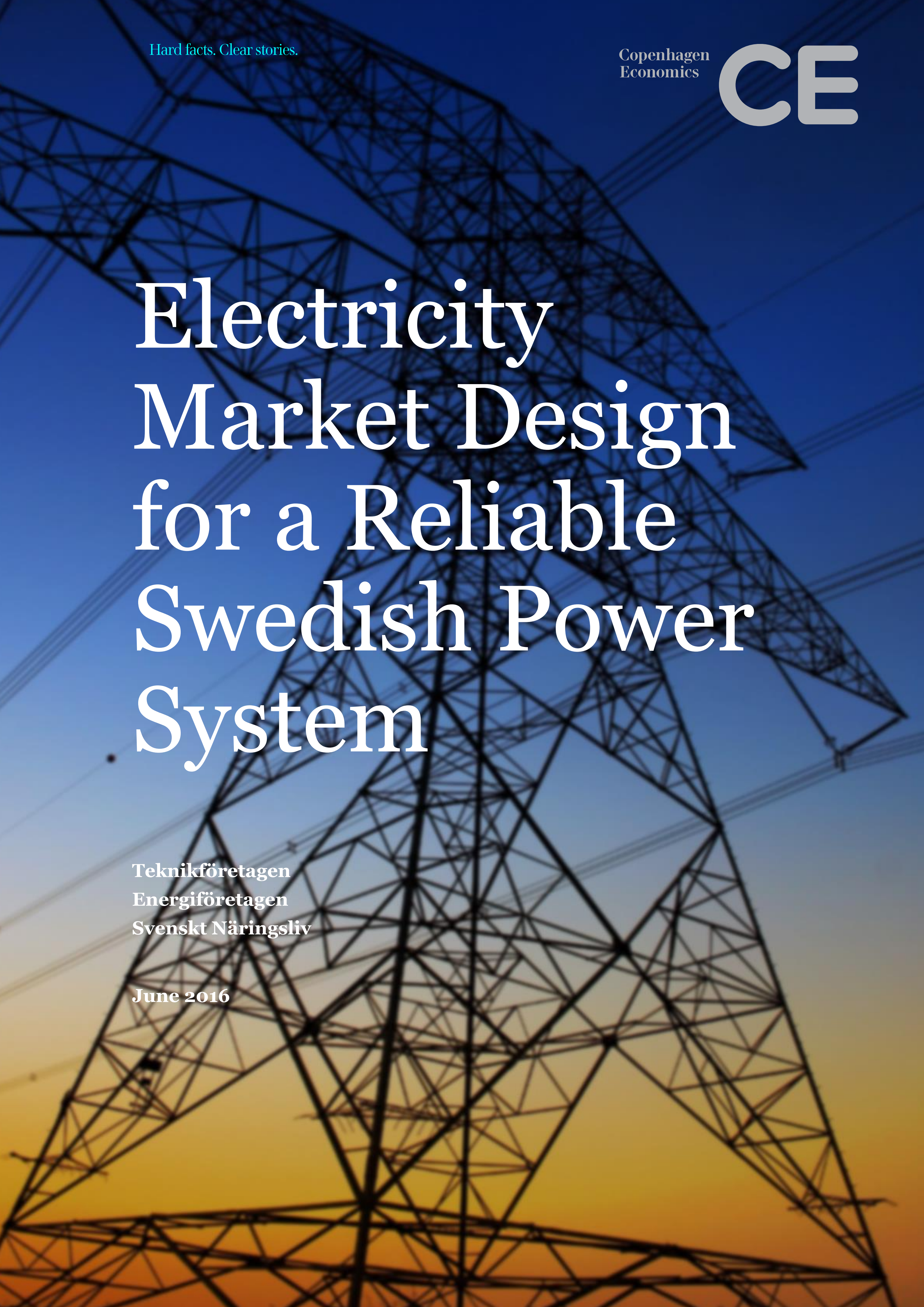

Electricity Market Design for a Reliable Swedish Power System

Teknikföretagen
Energiföretagen
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Sammanfattning

Sverige har genom åren gynnats av ett stabilt och välfungerande kraftsystem, men står nu inför en avgörande fråga: kan elmarknaden, så som den ser ut idag, fortsätta att fungera väl även framöver? I den här rapporten granskar vi de utmaningar som ett framtida elsystem kommer att ställas inför och analyserar vilka marknadsarrangemang som bäst kan bidra till kostnadseffektivitet och konkurrenskraft, leverans- och energisäkerhet, och samtidigt bidra till att nå Sveriges miljömål.

Sammanfattningsvis finner vi att dagens marknadsdesign kommer att kunna tjäna Sverige väl framöver, även med stora förändringar. På kort sikt finns ett behov att undvika en ohanterlig avveckling av kärnkraften, men detta är en fråga för energipolitiken som helhet, inte för marknadsdesign. På längre sikt finns goda möjligheter att vidareutveckla och anpassa dagens elmarknadsdesign så att den fungerar väl även i ett framtida elsystem.

För att vidareutveckla och anpassa designen krävs handlingskraft. I den här rapporten identifierar vi tjugo konkreta förslag på åtgärder som tillsammans möjliggör en fortsatt avreglerad elmarknad och främjar mål för den ekonomiska tillväxten, energisystemet, och miljön. Politiskt engagemang är avgörande. Minskad politisk osäkerhet kan i själva verket vara den enskilt viktigaste faktorn för att få till stånd de investeringar som i framtiden krävs för ett mer tillförlitligt kraftsystem.

Det finns dock en risk att energipolitiken tar en annan väg. Mål för mer (förnybar) elproduktion leder till utbyggnad av produktion samtidigt som efterfrågan står nära nog stilla. Detta skapar påfrestningar som riskerar att motarbeta de mekanismer som krävs för en välfungerande elmarknad, inte minst då investeringstakten särkopplas från elpriset. Marknaden blir också beroende av en osäker och ifrågasatt politik. Att stänga befintliga kraftverk för att skapa utrymme för ny produktion är dessutom kostsamt, och det är inte uppenbart hur en sådan utveckling bidrar till miljömålen. Det finns också en risk att energipolitiken äventyrar de mekanismer som i tryggar långsiktig tillförlitlighet i elsystemet.

Det är troligt att vi snart når ett vägskäl: att antingen stärka de marknadsmekanismer ligger till grund för dagens elmarknad, eller att ta ytterligare steg mot mer reglering. Det senare alternativet kan inbegripa en *kapacitetsmekanism*, varvid en tillsynsmyndighet beslutar om vilka investeringsvolymer som behövs. Det vore ett stort och troligen irreversibelt steg, med risk för långa ledtider och högre kostnader. För- och nackdelar måste vägas mycket noga. Vi bör beakta att ny teknik för energilagring, elektrifiering, automatisering och smarta elnät utvecklas i snabb takt, och kan bidra till att skapa ett flexibelt och robust framtida elsystem även utan reglering av kapacitetsvolymen.

Det finns fortfarande tid att förbereda och anpassa elmarknadsdesignen inför olika framtidsscenarier. En förutsättning är att beslut om kärnkraftens roll efter 2020 kan hanteras. Såvitt ingen akut kris uppstår finns det därefter tid för att lägga grunden för ett välfungerande framtida elsystem genom att förbättra den nuvarande utformningen av elmarknaden.

Sverige har ett starkt utgångsläge

Kombinationen av en avreglerad marknad och nordisk integration av elsystemet har åstadkommit en välfungerande svensk elmarknad och har, enligt de flesta uppskattningar, lett till minskade kostnader. Det svenska systemet kombinerar en så kallad *energy-only-marknad* med en strategisk reserv av produktionskapacitet (den så kallade *effektreserven*), samt betydande överföringskapacitet till närliggande länder.[1] Denna kombination av olika lösningar har lett till att vi idag har ett mycket pålitligt elsystem.

Sverige befinner sig också i en avundsvärd position utifrån ett miljöperspektiv. Det svenska elsystemet är nästan är helt fritt från koldioxidutsläpp, medan andra länder inom EU står inför utmaningen att på kort tid fasa ut en stor mängd fossileldade kraftverk och ersätta dem med ny, koldioxidsnål produktion. Sverige har redan klarat av denna övergång och har därför ett mycket mindre behov av radikala förändringar.

Ett antal påfrestningar utmanar *status quo*

Trots dessa goda förutsättningar står det nuvarande systemet inför ett antal utmaningar.

För det första bygger både Sverige och regionen som helhet upp en betydande överkapacitet av elproduktion. Mål för ökad elproduktion från förnybara energikällor kräver nybyggnation av kraftverk. Samtidigt är efterfrågan närmast oförändrad. Hittills har nettoexporten av el till våra grannländer till stor del absorberat den resulterande produktionsökningen, men i framtiden är möjligheten till fortsatt produktion för export begränsad. En fortsatt produktionsexpansion, oaktat efterfrågan, innebär stora påfrestningar på elsystemet. Befintlig produktionskapacitet kommer att behöva lämna systemet för att återställa balansen mellan tillgång och efterfrågan, trots att det vore billigare att behålla dessa kraftverk än att bygga nya. Låga priser till följd av produktionsöverskott, i kombination med låga råvarupriser, äventyrar de investeringar som krävs för ett långsiktigt välfungerande elsystem.

För det andra sker denna kapacitetsutveckling parallellt med nya krav på befintliga kärnkraftverk. Betydande investeringar behövs för att uppnå de nya säkerhetsstandarder som träder i kraft år 2020. I en situation med låga elpriser, effektskatter och ekonomiskt svagare energiföretag är det möjligt att dessa investeringar inte kommer att vara kommersiellt gångbara. Fyra av de tio befintliga kärnreaktorerna kommer att avvecklas fram till 2020. Investeringsbeslut som möjliggör drift bortom 2020 har fattats för tre av de återstående sex reaktorerna. Utträde av stora kapacitetsvolymer riskerar att ske på så kort tid att elsystemet och -marknaden inte har någon möjlighet att anpassa sig.

För det tredje har produktionsmixen förändrats, framförallt genom utbyggnaden av vindkraften. Vindkraftens produktion varierar, och den måste därför kompletteras med annan typ av produktions- och konsumtionsanpassningar för att upprätthålla balansen mellan tillgång och efterfrågan. Hittills har detta påverkat tillförlitligheten i elsystemet mindre än vad vissa befarat. Vartefter andelen vindproducerad el ökar ställs dock allt

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[1] På en *energy-only*-marknad får elproducenter endast betalt för den el de producerar och konsumenter betalar endast för den el som de konsumerar. Det finns andra typer av marknadsdesign med separata mekanismer som betalar för kapacitet.

högre krav på möjligheten att snabbt balansera produktion och konsumtion. Det krävs också att övrig kapacitet förblir tillgänglig, men att den producerar under ett färre antal timmar. Detta kräver i sin tur mer frekventa pristoppar, det vill säga höga priser under korta perioder.

För det fjärde är den politiska osäkerheten utbredd. Politiska beslut i närtid kommer att kraftigt påverka framtida marknadsförhållanden och därmed investeringar, både för energiproducenter och för slutanvändare inom industrin. Vad som främst ligger bakom denna osäkerhet är bland annat avvecklingen av kärnkraften, mål för ytterligare investering i förnybar elproduktion, och den ovissa framtiden för EU:s system för handel med utsläppsrätter. Det är också otydligt om det finns tolerans och förståelse för det ökande behovet av kortsiktiga elpristoppar på de nivåer som krävs för investeringar i topplastkapacitet. Det faktum att elmarknadsdesignen kan komma att förändras leder också i sig till betydande osäkerhet. Investerare har därför starka incitament att vänta och se. Detta gäller särskilt för investeringar i sådan kapacitet som enbart utnyttjas under några få timmar varje år – investeringar som redan idag är svåra att räkna hem.

En *energy-only-marknad* kan fortsätta att säkerställa ett tillförlitligt och kostnadseffektivt elsystem i flera framtidsscenarier

De påfrestningar som beskrivs ovan har lett till att den aktuella elmarknadsdesignens lämplighet ifrågasätts. Vi undersöker detta med hjälp av tre olika framtidsscenarier, som målar upp olika politiska beslut och marknadsförhållanden. Sammantaget drar vi slutsatsen att den nuvarande marknadsdesignen, som är baserad på *energy-only*-principer, kan fortsätta att fungera väl i ett flertal tänkbara framtidsscenarier.

Dock finns det mycket att vinna på att ytterligare utveckla och anpassa dagens marknadsdesign till nya omständigheter. Vi föreslår en ambitiös handlingsplan som sträcker sig över tre tidshorisonter:

1. **Kort sikt: eliminera hotet om en kapacitetskris.** Undvik en plötslig och omfattande avveckling av kärnkraften. En decentraliserad marknadsprocess kan inte förväntas hantera en sådan osäker och storskalig förändring på mycket kort tid. Situationen har inte sin upprinnelse i marknadsdesign, och åtgärdas därför bäst också på annat sätt.
2. **Medellång sikt: stärk marknadsdesignen genom riktade reformer.** Genomför ett antal reformer av den nuvarande marknadsdesignen med syfte att ytterligare stärka marknadens mekanismer för att säkerställa elförsörjning och effektivitet. Vi sammanfattar ett tjugotal möjliga reformer i sex kategorier i figuren nedan.
3. **Lång sikt: återgå till ett marknadsstyrt system för investeringar.** På längre sikt krävs att nya investeringar dimensioneras till den faktiska efterfrågan på el i Sverige och Norden. Överproduktion riskerar annars resultera i att marknadspriserna frånkopplas den faktiska kostnaden för ny elproduktion. Många av de fördelar som finns med en konkurrensutsatt marknad riskerar då att sättas ur spel. I värsta fall kan det långsiktigt underminera kapaciteten som krävs för god tillförlitlighet i elsystemet.

Sex förslag för en framtida marknadsdesign

1	**Fastställ en standard för tillförlitlighet**	• Enas om en officiell tillförlitlighetsstandard baserad på ekonomiska principer och koppla den till VOLL • Inför denna standard i nätoperatörerens och reglermyndigheters verksamhet	4	**Förbättra intradags- och balans-marknader**	• Minska tidsramen för avräkning och handel • Introducera nya produkter för kapacitet- och systemtjänster • Granska balansavräkning och prissättning
2	**Minska marknads-störningar orsakade av den strategiska reserven**	• Minska direkt undanträngning genom att en förändring av driften • Minska snedvridningen genom att prissätta reserven till det högsta möjliga priset • Minska indirekt undanträngning genom att begränsa återinträde • Samordna strategiska reserver i Nordiska länder • Minska osäkerheten genom att klargöra reservens framtid	5	**Stimulera efterfråge-flexibilitet**	• Stöd utvecklingen av infrastruktur som främjar flexibilitet • Granska villkoren för efterfrågesidans deltagande i relevanta marknader • Se över prisincitament som skapas av nättariffer och skatter
3	**Stärk marknads-tron och prissättning vid brist**	• Höj pristaket till (en nivå närmare) VOLL • Säkerställ institutionell förankring för knapphetsprissätning • Stärk marknadstillsyn och -konkurrens • Främja mekanismer som minskar konsumentprisrisk • Undersök möjligheten att införa en capacity adder	6	**Förbättra villkoren för infrastruktur-investeringar och handel**	• Harmonisera nättariffer med grannländer • Anpassa prisområden när förhållanden ändras • Överväg flödesbaserad marknadskoppling • Minska ledtider för investeringar i produktionsanläggningar och nätinfrastruktur

Mindre fördelaktiga scenarier pekar på ökade påfrestningar på elsystemet runt 2025

En stärkt *energy-only*-marknad kan fortsätta att fungera väl i flera framtidsscenarier, men kan stöta på problem i andra. I synnerhet skulle en kombination av fortsatt överkapacitet i regionen som helhet och låga råvaru- och koldioxidpriser vara problematisk.

Vi simulerar möjliga utfall i ett sådant scenario med hjälp av en elmarknadsmodell. Analysen pekar på ökade påfrestningar på elsystemet under mitten av 2020-talet. Exportmöjligheter skulle begränsas av tilltagande överkapacitet i grannländer. Subventioner som leder till en växande överproduktion, skulle pressa ned elpriset till nivåer lägre än den långsiktiga produktionskostnaden för el, och investeringar i icke-subventionerad elproduktion skulle sannolikt vara omöjliga. Långsiktiga återinvesteringar och fortsatt drift av befintliga kraftverk skulle också riskera att äventyras. Investeringar i topp- och reservkapacitet, som kan krävas med en ökande andel vindkraft, skulle endast vara lönsamt med tätare och högre pristoppar. De framtida utsikterna för alla investeringar skulle vara starkt beroende av politiska beslut snarare än av en välfungerande marknad.

Det är möjligt att en *energy-only*-marknad skulle kunna hantera ett sådant scenario, givet att: elpriserna tillåts variera så att pristoppar som möjliggör investeringar uppstår; avvecklingen av befintliga kraftverk sker gradvis, med tillräckliga ledtider och förutsägbarhet; investerare har tillräckligt förtroende för marknadens stabilitet, spelregler och politiska åtaganden. En fortsatt välfungerande marknad skulle stödjas ytterligare av förbättrad efterfrågeflexibilitet genom lagring och automatisering, samt genom att smarta nät introduceras och integreras med den större marknaden.

En kapacitetsmekanism kan hantera vissa utmaningar i ett mindre fördelaktigt scenario, men innebär långa ledtider och eventuella risker

Hur väl en *energy-only*-marknad faktiskt skulle fungera i scenarier av det slag som beskrivs ovan är inte givet. Det är därför klokt att analysera och överväga vad andra marknadsalternativ skulle innebära. En möjlighet är att i likhet med ett flertal andra EU-länder införa en separat kapacitetsmekanism utöver den nuvarande effektreserven.

Det finns ett flertal designalternativ för kapacitetsreserver. Samtliga har gemensamt att myndigheter beslutar om hur mycket kapacitet som ska byggas, samt arrangerar en betalning för reservkapaciteten utanför marknaden för el. Figuren nedan sammanfattar de fem huvudsakliga alternativ som finns tillgängliga. Överlag är vår bedömning att ett auktionsbaserat system eller ett system med tillgänglighetsoptioner vore mest förenliga med den nordiska elmarknaden Nord Pool. Det krävs dock ytterligare analys för att fatta ett beslut om vilken lösning som är mest lämplig.

Det finns fem huvudkategorier av kapacitetsmekanism

			Kapacitetsmekanism	Riktad	Marknads-omfattande	Exempel
Volymbaserad	Finansiell	1	**Tillgänglighetsoptioner (’Reliability options’)**	☐	☑	• Italien (2018-) • Irland (2017-)
Volymbaserad	Finansiell	2	**Kapacitetskrav (’Capacity obligation’)**	☐	☑	• Frankrike (2016-17)
Volymbaserad	Fysisk	3	**Kapacitetsauktion (’Capacity auction’)**	☐	☑	• Storbritannien
Volymbaserad	Fysisk	4	**Strategisk reserv (’Strategic reserve’)**	☑	☐	• Danmark • Sverige • Finland • Tyskland
Pris-baserad	Fysisk		**Kapacitetsbetalning (’Capacity payment’)**	☑	☑	• Irland • Spanien

Källa: Copenhagen Economics baserat på ACER (2013) och Europeiska Kommissionen (2016).[2]

[2] ACER, ‘Pursuant To Article 11 Of Regulation (EC) No 713/2009, The Agency For The Cooperation Of Energy Regulators Reports On: Capacity Remuneration Mechanisms And The Internal Market For Electricity’; European Commission, ‘Commission Staff Working Document. Accompanying the Document Report from the Commission Interim Report of the Sector Inquiry on Capacity Mechanisms’.

Vilken kapacitetsmekanism som är bäst lämpad beror på marknadssituationen samt mekanismens syfte

Kapacitetsmekanism	Syfte	För- och nackdelar
Strategisk reserv Den systemoperatör som är ansvarig för stamnät och elkraft (TSO; Svenska kraftnät i Sverige) upphandlar el som aktiveras vid kapacitetsbrist. Upphandling sker ofta genom auktion. Effektreserven aktivera när övriga bud är otillräckliga för att tillgodose efterfrågan. En formell tillgänglighetsstandard behöver inte specificeras, men däremot måste reservens volym vara bestämd på förhand.	• Säkerställa en tillräcklig elförsörjning på kort sikt genom att upprätthålla reservkapacitet. • 'Fylla på' med kapacitet utöver vad marknaden förväntas tillhandahålla.	+Begränsad omfattning, liten administrativ börda. - Bemöter inte strukturella problem eller regulatoriska misslyckanden. - Kan störa marknadens funktion, då kapacitet hålls utanför marknaden, vilket i sin tur påverkar investeringsbeslut. - Prisnivån vid vilken reserven aktiveras sätter ett tak på elpriset, vilket hindrar knapphetspriser på högre nivå från att uppstå.
Kapacitetsbetalning Systemoperatören betalar en viss summa per enhet av kapacitet som finns tillgänglig vid efterfrågetoppar. Kan liknas vid inmatningstariffer.	• Långsiktig försörjningstrygghet genom att förse elproducenter med tillförlitliga investeringssignaler. • Försöker lösa marknadsspecifika-, och generella problem som inte är bundna till särskilda geografiska platser eller produktionstyper.	+Säkerställer elförsörjning på lång sikt. - Kostsamt om det finns en stor mängd tillgänglig kapacitet. - Kan leda till höga elpriser för konsumenter. - Motverkar inte prisvolatilitet.
Kapacitetsauktion En extern part, exempelvis systemoperatören, bestämmer vilken volym kapacitet som skall finnas tillgänglig vid efterfrågetoppar. I en auktion lämnar producenter, och ibland storkonsumenter, bud som anger den ersättning de kräver för att hålla en viss mängd kapacitet tillgänglig under höglasttid. Priset bestäms av marginalbudet och gäller för samtliga budgivare.	• Direkt åtgärda kapacitetsbrister genom att upphandla den kapacitet som behövs.	+Kan på ett effektivt sätt åtgärda kapacitetsbrist på kort sikt. - Risk att för mycket kapacitet köps upp på grund av att systemet förlitar sig på TSO:ns beslut kring hur mycket kapacitet som behövs. - Svårigheter att se till att alla relevanta resurser kan delta och bidra till försörjningstrygghet, särskilt vad gäller transmissionskapacitet och efterfrågeflexibilitet.
Tillgänglighetsoptioner Återförsäljare köper tillgänglighetsoptioner för att möta efterfrågan vid kapacitetsbrist. Säljare (huvudsakligen elproducenter) garanterar att erbjuda kapacitet till ett visst pris om en kapacitetsbrist skulle uppstå. De går då miste om extraintäkter vid pristoppar, men i gengäld får de ett stabilt inkomstflöde.	• Hanterar snabbt finansieringsproblem av investeringar genom att tillåta knapphetspriser, men skyddar samtidigt konsumenter från pristoppar.	+Förser marknaden med prissignaler, vilka i sin tur ger marknadens aktörer investeringssignaler, samtidigt den prisvolatilitet för konsumenter kan undvikas. - Garanterar inte försörjningstrygghet, utan förser marknadens aktörer med ekonomiska incitament att tillhandahålla kapacitet.
Kapacitetskrav Storkonsumenter och återförsäljare av el är skyldiga att ha en marginal mellan tillgänglig- och utnyttjad kapacitet. Kravet kan ibland uppfyllas genom bilaterala avtal som innebär att innehavaren av kontraktet tillåts avyttra kapacitet. Kontrakten är föremål för handel och säljs av elproducenter. Om den i kontraktet utlovade kapaciteten inte finns tillgänglig utfärdas en straffavgift.	• Löser kapacitetsbrist med begränsad administration och liten påverkan på marknaden.	+Mängden kapacitet som behövs är inte bestämd av en central aktör utan prissignaler förser marknaden med nödvändiga incitament för att hålla kapacitet tillgänglig. - Garanterar inte försörjningstrygghet på kort sikt. - Kapacitet kan fortfarande under- eller överproduceras. Det beror på hur hög straffavgiften samt på andra administrativa parametrar. - Kan försvåra för nya producenter att ta sig in på marknaden och därför leda till marknadsmakt för befintliga aktörer.

Det kan verka lockande att direkt styra över hur mycket kapacitet som finns tillgänglig. Samtidigt finns det också betydande begränsningar och nackdelar att beakta:

- **Kapacitetmekanismer löser inte nödvändigtvis underliggande problem.** Kapacitetsmekanismer är till för att lösa problem med kapacitetsbrist, inte överskottskapacitet. Fortsatta subventioner av en viss produktionsteknologi i kombination med kapacitetsbetalningar för övriga teknologier innebär en risk för höga kostnader för att upprätthålla systemet.
- **Kapacitetsmekanismer är komplexa och tar tid att implementera.** Erfarenheter från andra länder vittnar om att kapacitetsmekanismer kan vara mycket komplicerade att införa och att de ofta utformas felaktigt. Det krävs därmed ofta långa ledtider och många korrigeringar innan man uppnår ett välfungerande system. Kapacitetsmekanismer är därför inte lämpade för att lösa problem på kort sikt.
- **Samordning med grannländer är nödvändig.** En svensk kapacitetsmekanism skulle ha stor påverkan på Nord Pool. Det är därför nödvändigt med regional samordning för att undvika att den nordiska marknaden inte försvagas. Den nordiska marknaden är dessutom viktig för Sveriges elförsörjning och elsystemets stabilitet. En sådan samordning leder troligtvis till ännu längre ledtider och mer komplexitet när det kommer till utformningen av kapacitetmekanismen.
- **En kapacitetsmekanism är förmodligen oåterkallelig.** När en kapacitets-mekanism har införts blir den central för merparten av alla företagsekonomiska beslut och investeringar. Den är därför mycket svår att avveckla. Det innebär också ett stort steg mot en återreglering av investeringar, då investeringar som inte stödjs av subventioner eller av ett kapacitetsbetalningssystem troligen inte kommer att vara lönsamma.
- **Kapacitetmekanismer kan orsaka kedjereaktioner.** En kapacitetsmekanism får flera konsekvenser. Exempelvis påverkas elpriser och gränsöverskridande handel om olika länder har olika kapacitetsmekanismer.
- **Förbättrad teknologi på efterfrågesidan kan erbjuda alternativa lösningar.** Om elanvändningen kan bli mer flexibel blir kapacitetsmekanismer inte lika nödvändiga. Den utveckling som nu pågår inom lagring, automatisering och smarta nät är lovande, och utgör i sig en anledning till att inte fatta förhastade beslut.

I sammanfattning finns stora utmaningar med införandet av en kapacitetsmekanism. Det är möjligt att de går att överbrygga, men risken blir dessutom större om den införs i en situation som redan präglas av stor osäkerhet. En kapacitetsmekanism är därför inte ett alternativ till att hitta ett mer systematiskt och stabilt förfaringssätt för att fatta beslut om investeringar i Sveriges framtida elförsörjning.

Att välja mellan olika alternativ kräver att olika mål inom energipolitiken vägs mot varandra

Beslut om framtidens elmarknadsdesign måste ta hänsyn till energipolitikens tre huvudsakliga mål: att garantera tillförlitlighet och försörjningstrygghet, och säkra de investeringar i kapacitet som detta kräver; att främja kostnadseffektiv och tillgång till el till konkurrenskraftiga priser; samt uppfyllelse av energi- och klimatrelaterade miljömål. Överlag finner vi att konflikten mellan dessa mål och nuvarande elmarknadsdesign är mindre än vad som ofta antas i den aktuella debatten. Nedan listar vi några av de faktorer som behöver utvärderas i valet av framtida elmarknadsdesign:

1. Försörjningstrygghet och investeringar

- Det tydligaste hotet mot elförsörjningstryggheten är en ohanterligt snabb avveckling av kärnkraften. Denna fråga bör inte hanteras genom marknadsdesignen, dels för att ledtiden innan förändringar får effekt är för långa, dels för att de underliggande problemen inte beror på några felaktigheter i marknadsdesignen.
- Försörjningstrygghet kan i princip alltid ökas genom en kapacitetsmekanism. Det har dock en kostnad. Frågan är därför snarare om en *energy-only*-marknad kan tillgodose tillräcklig tillförlitlighet. Erfarenheten i Sverige såväl som internationellt är att förnyade satsningar på *energy-only*-principer kan avvärja problem med kapacitetsbegränsningar. Samtidigt går utvecklingen av efterfrågebaserade lösningar fortsatt framåt.
- Den befintliga effektreserven kan fortsättningsvis stödja försörjningstryggheten, även på en *energy-only*-marknad. Om den ska finnas kvar på längre sikt bör den dock reformeras och göras mindre marknadsstörande. Till skillnad från en marknadsomfattande kapacitetsmekanism kan effektreserven efter en tid fasas ut.
- Osäkerhet kring framtida politiska beslut och reformer utgör ett stort hinder för investeringar och därmed försörjningstrygghet. En tydlig strategi och principinriktning för framtidens elsystem kan därför vara den enskilt viktigaste frågan för framtida försörjningstrygghet.
- Ett regionalt integrerat elsystem är viktigt för försörjningstryggheten. Förändringar av marknadsregler och regleringar med syfte att ytterligare säkra elförsörjningen får också starkare genomslagskraft om de koordineras på hela den nordiska marknaden, jämfört med om de begränsas till den svenska marknaden. Samordning gör också att förändringarna får mindre konsekvenser för gränsöverskridande elhandel.

2. Kostnad och konkurrenskraft

- Subventioner till ny förnybar energi är kostsamma, inte i första hand på grund av att förnybar el är dyrare än annan ny elproduktion, men eftersom att det är dyrare att bygga ny kapacitet än vad det är att använda sig av befintliga anläggningar. Detta gäller oavsett om anläggningen använder förnybara energikällor eller inte.
- Subventioner för ett kraftslag påverkar hela marknadens funktion, även om stödsystemet likt elcertifikatsystemet i sig är 'marknadsbaserat'. Kvoter ökar takten i vilken kapacitet tillkommer och avvecklas. Priset på el och förutsättningarna för all produktion som inte är subventionerad ändras. I längden leder det till ett dyrare elsystem.
- Subventioner kan på kort sikt leda till lägre priser som gynnar konsumenter. Detta betyder inte att totalkostnaden är lägre, utan beror på en kortsiktig omfördelning av resurser från producenter till konsumenter. I slutändan kommer dock konsumenterna eller skattebetalarna att få stå för de extra kostnader som det innebär att bygga ut och avveckla kapacitet i en snabbare takt.
- Även en perfekt utformad kapacitetsmekanism medför högre kostnader än en *energy-only*-lösning. Detta kan liknas vid en försäkringspremie som måste betalas för att öka beståndet av kapacitet. Dessutom tillkommer kapacitetsmekanismens komplexitet

och osäkerhet, som båda bidrar till risken att kostnaden för elsystemet som helhet ökar.

- En stor fördel med en konkurrensutsatt marknad är möjligheten att främja konkurrensen mellan olika lösningar. Att reglera fram mer av dagens lösningar kan innebära att framtidens tekniska innovationer antingen uteblir eller inte kan utnyttjas till fullo. Teknik och affärsmodeller förändras snabbt. Ökad framtida efterfrågeflexibilitet och möjligheter till energilagring kan mycket väl visa sig mer kostnadseffektiva än dagens lösningar.

3. Miljömål

- Ökad tillförsel av förnybar el i Sverige har begränsad klimatnytta för dagens elsystem som redan är nästintill fossilfritt. De kraftverk som kan komma avvecklas för att lämna plats till nya anläggningar är redan fria från koldioxidutsläpp.
- Förnybar el i Sverige kan i princip ersätta viss fossil elproduktion i andra länder. I de scenarier vi analyserar skulle detta dock vara beroende av en långt fördjupad marknadsintegration, samt högre elpriser (och minskad utbyggnad av förnybar kraft) i närliggande marknader för att en sådan strategi ska vara hållbar på lång sikt,
- Den nuvarande marknadsdesignen kan stödja investeringar i förnybar el. Vår modellering tyder på att vindkraft, i ett scenario där överkapacitet reducerats (exempelvis på grund av ökad efterfrågan) och högre råvarupriser, kan nå tillräckliga intäkter inom den nuvarande marknadsmodellen. Däremot kan ingen marknad stödja investeringar i ny kapacitet, oavsett typ, om marknaden befinner sig i en situation med överutbud.

Ett vägskäl: en fortsatt avreglerad marknad eller ytterligare reglering

Valet av marknadsdesign är en del av ett större val om hur elsystemet bör organiseras. I grova drag finns två alternativ: att återgå till en avreglerad elmarknad, eller att acceptera ett betydligt mer reglerat system.

En starkare ställning för en avreglerad elmarknad skulle motiveras främst av vinsterna för konkurrenskraft och lägre kostnader. Ett antal riktade reformer skulle genomföras med syfte att anpassa elmarknaden till nya förhållanden och säkerställa tillförlitligheten och marknadens effektivitet. Färre regleringsåtgärder skulle minska osäkerheten. På längre sikt kan ökad efterfrågeflexibilitet och ökad handel ytterligare förbättra systemets funktion. På sikt skulle det krävas att investeringar i ny kapacitet speglar tillväxten i efterfrågan, med elpriset snarare än politiska kvoter som den centralt koordinerade mekanismen för marknadsaktörernas beslut. Med tanke på den nuvarande elproduktionens återstående livslängd och omsättningstakt, skulle övergången till nya kraftslag sannolikt ske relativt långsamt. Detta beror inte på att marknadsdesignen i sig är ogynnsam för förnybar eller annan elproduktion, utan på att det är mindre kostsamt att fortsätta använda befintliga anläggningar än att bygga nya.

Ökad reglering skule motiveras av en önskan om att snabbt styra om elproduktionsmixen på grund av miljömässiga eller andra skäl. Detta skulle innebära fortsatta kvoter och subventioner för utvalda former av ny elproduktion för att påskynda omställningen. En *energy-only*-marknad skulle kunna fortsätta att fungera i vissa scenarier, men under svåra förhållanden (stor överkapacitet, låga råvarupriser, begränsad handel, och brist på politiskt engagemang) kan det bli nödvändigt att införa en kapacitetsmekanism för att tillgodose tillförlitlighet. Om spänningarna blir akuta, kan ytterligare lagstiftningsåtgärder bli nödvändiga för att förhindra utträde av kapacitet eller tidigarelägga investeringar som förhindras av de låga energipriser som blir resultatet av subventioner på elproduktion.

Politiska preferenser måste avgöra vilken av dessa vägar som väljs. Det är troligt att ett tillförlitligt elsystem skulle kunna uppnås oavsett utfall, om än med mycket olika kostnadskonsekvenser. Det största hotet mot försörjningstryggheten kommer istället från osäkerhet, och av motstridiga principer för olika aspekter av energipolitiken. Det är därför angeläget att först lösa kortsiktiga problem, för att sedan fastställa en övergripande färdriktning.

Executive summary

Sweden has benefited from a stable and well-functioning electricity system, but now faces a fundamental question: can the current organisation of the electricity market continue to work well in a situation of new, emerging pressures? In this report we review the challenges facing the future electricity system, and consider options for how different market design options can best continue to serve objectives of cost effectiveness and competitiveness, energy security and reliability, and environmental targets.

We find that the current market design can continue to serve Sweden well. There is a short-term need to avoid a chaotic crunch through the simultaneous and large-scale exit of remaining nuclear power – but this is a matter for wider energy policy, not for market design. Longer-term, there is ample opportunity to adapt and further develop the current market design to a new emerging situation and set of requirements.

Seizing this opportunity will require decisive steps. We identify and elaborate twenty concrete measures in this report that together reinforce the use of a liberalised electricity market to further future economic, energy, and environmental goals. Political commitment will be essential to succeed. Indeed, reducing political uncertainty may be the single most important factor in enabling investments required for a reliable electricity system.

In contrast, current energy policy risks taking a different course. In particular, targets for renewable energy in practice amount to mandating the construction of new electricity capacity, even as demand is largely stagnant. As a result, investment is increasingly unlinked from the market; electricity prices pushed down; and future market conditions highly dependent on contested and uncertain policymaking. As we describe, this is storing up significant tensions. It also is costly, with unclear contribution to environmental or other objectives. In the longer run, it may put at risk the very mechanisms whereby the current electricity market design safeguards the reliability of supply.

At some point, there therefore may be a fork in the road: either to recommit to the market principles that have underpinned the electricity market for the last two decades; or else to take further steps towards increased regulation of investment. On the latter road, one option is a *capacity mechanism,* whereby regulators decide on investment volumes and procure it separately from the electricity market. However, we caution that this would be a major undertaking. It would take time to implement, and should be preceded by careful evaluation of costs and benefits. It also would be a backward step, even as technologies for energy storage, electrification, automation, and smart grids are emerging as alternative options to provide flexibility and reliability for future electricity systems.

We are in any case not yet at the point where such decisions must be taken. Sweden still has time to prepare and equip itself for a range of future scenarios. The first step must be to avoid a near-term threat to the security of supply. Absent any immediate crisis, there is then an opportunity to improve the current market design in a number of ways, as a foundation of a well-functioning future electricity system.

Sweden starts from a strong position

Liberalisation and regional integration of the Swedish electricity system has achieved a well-functioning market, and by most estimates reduced costs. The system combines a so-called *energy-only* market with a strategic reserve of backup capacity and substantial interconnection.[3] These arrangements together have proven capable of supporting a highly reliable electricity system.

Sweden also finds itself in an enviable position of a power system almost entirely free of carbon-dioxide emissions. This sets it apart from other countries in the European Union, most of which face a daunting challenge of rapidly phasing out a large amount of existing, fossil-fuel plants and replacing them with new, low-carbon power. Sweden already has completed this transition, and faces much less pressure for rapid change.

A number of pressures now challenge the status quo

Despite this strong starting point, a number of pressures are now building up.

First, the Swedish and wider regional electricity system has significant and growing over-capacity. Mandates for increased production from renewable energy sources require the construction of large volumes of new power plants. To date, increasing net exports have largely absorbed this increase in supply. However, with stagnant domestic demand and overall regional over-supply, continued expansion in Sweden can no longer rely on this as a future option. Absent large exports, large volumes of existing generation will eventually need to exit to restore a balance between supply and demand – even though existing plants are less costly than the new plants being built. Meanwhile, low prices resulting from the glut in production as well as low commodity prices also place at risk a range of important investment decisions required for a well-functioning system in the longer term.

Second, and more immediately, this capacity development has combined with new regulatory requirements to prompt a possible abrupt closure of remaining nuclear power plants. Significant investments are needed to achieve new safety standards required from 2020. These investments might not be commercially viable in a situation of low prices, taxes on capacity, and financially weaker energy companies. Four of the ten existing nuclear reactors will retire in the period to 2020. Of the remaining six, investment in three has been committed, while three remain undecided. The risk is not only that closures would impose large costs, but also that large capacity exits the market in such a compressed time period that security of supply is put at risk.

Third, the production mix is changing, notably through the introduction of wind power. Wind turbines produce electricity intermittently (when the wind blows) and must therefore be complemented with other production or adjustments to consumption in order to maintain a balance between supply and demand of electricity. To date, this has put less strain on the reliability of the electricity system than some had feared. However, as the share of wind production grows, the system will need increased capabilities to rapidly adjust output and consumption. It also requires that non-wind capacity remains

3 In an energy-only, market producers receive payment only for the electricity they produce, and consumers pay only for the electricity they use. This is in contrast to some other market designs with a separate mechanisms to pay for capacity.

available, but that it runs for a smaller number of hours. With the current market design, this is likely to require more frequent price spikes, with high prices during short periods.

Fourth, uncertainty is now deep and endemic. Near-term political decisions fundamentally affect future market conditions and thus the case for investment – both for energy producers and for industrial users. Key factors include possible interventions to prevent the exit of nuclear power; the extent of mandates to build new renewable production capacity; the unclear future of the EU emissions trading scheme; whether electricity prices will be allowed to spike at the levels required to remunerate backup and flexible capacity; and the possibility that market design and other regulations will be changed. Investors have strong incentives to wait and see. This is especially the case for the already strained case for investment in peak capacity, i.e., plants that runs for only few hours of the year.

An energy-only-market can continue to provide a reliable and cost-effective electricity system in a range of future scenarios

These pressures have called into question whether the current market design is fit for purpose. We examine this in three different future scenarios for regulatory decisions and commodity prices. Overall, we conclude that the current market design – based on *energy-only* principles – can in fact continue to serve well in a number of plausible future developments.

This requires a proactive agenda to continue to adapt the market design to new circumstances, across three time horizons:

1. **Near-term: remove the threat of a capacity crisis.** Avoid the abrupt and simultaneous exit of large volumes of nuclear power. Any decentralised market process will struggle to manage sudden, uncertain, and large-scale change, caused by factors largely unrelated to market design.

2. **Mid-term: strengthen the market design through targeted reforms.** Implement a number of reforms to the current market design to strengthen mechanisms that are becoming increasingly important to ensure reliability and efficiency. We summarise a number of recommendations in the figure below.

3. **Longer-term: revert to a market-based system for investment.** In particular, limit mandates to increase production ahead of growth in demand (in Sweden or regionally) to absorb it. The resulting over-production otherwise risks affecting the entire market, structurally disconnecting market prices from underlying costs of supplying electricity. Whether or not the support scheme for renewable energy is itself 'market based', this weakens many of the benefits of a competitive market. At worst, it can combine with other factors to undermine the very mechanisms whereby the long-term reliability is achieved.

Six principles for further developing the current market design

1 Define a reliability standard
- Agree on an official reliability standard based on economic principles and linked to VOLL
- Incorporate standard in TSO operations and market design

2 Reduce distortions caused by the strategic reserve
- Reduce direct crowding out by changing operation
- Reduce distortion by pricing the reserve at the maximum price
- Reduce indirect crowding out by limiting market re-entry
- Coordinate the strategic reserve across Nordic countries
- Reduce uncertainty by clarifying the future status of the reserve

3 Strengthen confidence and scarcity pricing
- Raise the price cap to (a level closer to) VOLL
- Ensure institutional anchoring and precommitment
- Clarify market oversight and competition law
- Support mechanisms to mitigate consumer price risk
- Investigate the option of introducing a scarcity adder

4 Improve intraday and balancing markets
- Reduce time to gate closure and trading frequency
- Introduce new products for capabilities and system services
- Review balancing settlement procedures

5 Stimulate demand flexibility
- Support development of demand response infrastructure
- Review conditions for demand-side participation in all relevant markets
- Review price incentives created by grid tariffs and taxation

6 Improve conditions for infrastructure investment and trade
- Harmonise grid tariffs with neighbouring countries
- Evolve price areas dynamically in response to changing conditions
- Consider flow-based market coupling
- Reduce lead times for investments in generation plant and grid infrastructure

Adverse scenarios could see a return of pressures on the current market design by the mid 2020's

While a strengthened energy-only market could continue to function well in a range of future situations, it could struggle to perform in some scenarios. In particular, a combination of continued growth of regional over-capacity and longer-term low commodity prices would pose challenges.

We simulate potential outcomes of such an adverse scenario using a model of the power market, and find a range of tensions re-emerging by the mid-2020s. Export opportunities would be limited by growing over-capacity in neighbouring countries. Subsidies and resulting growing over-production could suppress electricity prices below the long-term cost of providing new electricity, with far-reaching consequences for the market as a whole. Investment in any non-subsidised generation would likely be unviable. Longer-term reinvestment and operation of existing power plants would be called into question. Investment in peaking and back-up capacity that may be required with increasing shares of wind power would be viable only with more frequent price spikes. The future prospect of any investment would be strongly dependent on policy decisions rather than on well-functioning market.

It is possible that an energy-only market could handle even this scenario – if prices are allowed to adjust (and spike) as required to underpin the investment required; the exit of existing plants were orderly and gradual; and investors had sufficient confidence in the stability of market rules and political commitment. It also could be helped by new technologies and business models, as storage, automation, and smart-grid technologies are adopted and integrated into the overall market.

A capacity mechanism could address some challenges in an adverse scenario, but would have long lead time and entail a range of additional risks

Favourable outcomes are not assured, and it is prudent to consider what other market options could entail. One option would be to introduce a *capacity mechanism* beyond the current strategic reserve. The introduction of such mechanisms is now under consideration or implementation in a number of EU countries.

There are a number of design options for such mechanisms. They have in common the need for regulators to decide how much capacity should be built, and then a mechanism to create payments for this separately from the energy market. The below table summarises the five main options available. Overall, our assessment is that either an auction-based system or well-designed reliability options would be those most compatible with the pre-existing Nord Pool electricity market. However, there is a long road to fully specifying and choosing between options.

Five types of capacity remuneration mechanism

		Capacity mechanism	Type of mechanism: Targeted	Type of mechanism: Market-wide	Examples of countries where used
Volume-based	Financial	1 Reliability option	☐	☑	•Italy (2018-) •Ireland (2017-)
Volume-based	Financial	2 Capacity obligation	☐	☑	•France (2016-17)
Volume-based	Physical	3 Capacity auction	☐	☑	•UK
Volume-based	Physical	4 Strategic reserve	☑	☐	•Denmark •Sweden •Finland •Germany
Price-based	Physical	5 Capacity payment	☑	☑	•Ireland •Spain

Note: List of countries is not exhaustive.

Source: Copenhagen Economics based on ACER (2013) and European Commission (2016).[4]

[4] ACER, 'Pursuant To Article 11 Of Regulation (EC) No 713/2009, The Agency For The Cooperation Of Energy Regulators Reports On: Capacity Remuneration Mechanisms And The Internal Market For Electricity'; European Commission, 'Commission Staff Working Document. Accompanying the Document Report from the Commission Interim Report of the Sector Inquiry on Capacity Mechanisms'.

The choice of capacity mechanism depends on market settings and objectives

Capacity mechanism	Objective	Advantages and disadvantages
Strategic reserve The transmissions system operator (TSO; *Svenska kraftnät* in Sweden) procures capacity to be deployed in periods of scarcity. The procurement is often done through auction. The strategic reserve is activated only when other bids fail to clear the market. No explicit reliability standard needs to be specified, but the volume of the reserve must be decided.	• Ensure short-term security of supply by keeping some generation available in times of scarcity. • 'Top up' the capacity in addition to what the market is expected to provide.	+Limited in scope and administrative burden. - Does not address underlying structural issues or regulatory failures. - May interfere with investment decisions that would contribute to security of supply. - If activation is triggered by a threshold price, this effectively acts as a price cap in wholesale markets, undermining scarcity pricing.
Capacity payment The TSO pays a certain sum of money per unit of capacity available during peak load times. Similar to feed-in-tariffs.	• Ensure long term security of supply by providing reliable investment signals to owners of generating capacity. • Address market-wide and general problems that are not restricted to certain locations or generation types.	+Contributes to long-term security of supply. - Costly if all available capacity is remunerated. - Could prop up unprofitable capacity at high cost to consumers. - Does not address price volatility
Capacity auction / central buyer mechanism An external party (e.g., the TSO) determines the amount of capacity to be available during times of peak load. Producers (and sometimes large consumers) bid in an auction to make capacity available. The marginal bid sets the price, which is paid to all winning bidders.	• Address general shortage of capacity directly by procuring the amount of capacity needed.	+Can effectively resolve problem of short-term capacity shortage. - Risk of over-procurement due to heavy reliance on central decision-making to determine required capacity. - Difficult to ensure participation by all resources that could contribute to improve reliability, notably interconnectors and demand resources.
Reliability options Retailers are required to buy ROs to meet their demand at time of scarcity. Sellers, i.e. generation owners, commit their available capacity at times of scarcity and forego revenue from price spikes in return for a stable revenue stream.	• Directly addresses the problem of 'missing money' for investments by allowing scarcity pricing (as revenue streams), while at the same time insulating consumers from price peaks.	+Provides price signals required for investment while avoiding controversial price volatility. - May not guarantee security of supply, only provides economic incentives to sell capacity at reference price.
Capacity obligation Large consumers and electricity retailers are requires to ensure a margin between available capacity and delivered power. The obligation can be met through bilateral contracts that allow the holder of the contract to dispose of capacity. The contracts be tradable certificates sold by generation owners (or storage and demand reduction). If the promised capacity is not available, a penalty fee must be paid.	• Solves a general shortage of capacity with limited administrative intervention.	+The amount of capacity need not be determined centrally; instead, price signals provide the necessary incentives. - Does not guarantee short-term security of supply, only provides an economic disincentive for failing to keep capacity available. - Depending on the level of the penalty fee and other administrative parameters, capacity may still be over- or under-procured. - May create barriers to entry of new generation, leaving room for existing capacity providers to exercise market power to the detriment of consumers.

While asserting control over the amount of capacity may seem tempting, the introduction of a capacity mechanism should be weighed carefully:

- **Capacity mechanisms may not resolve key underlying tensions.** Capacity mechanisms are intended to address the problem of a *lack* of capacity, not over-capacity. The combination of continued subsidies for one category of supply, and capacity payments for the remainder would risk high costs.
- **Capacity mechanisms are complex and take time to introduce.** The experience with capacity mechanisms internationally shows that they are complex to implement and prone to design mistakes, and often require both long lead times and subsequent repeated redesign to perform well. They therefore are not a plausible route to resolving near-term problems.
- **Regional coordination would be necessary.** A Swedish capacity mechanism would strongly affect the wider Nordic electricity market. Coordination therefore would be required to avoid undermining the functioning of the overall regional market, which in itself is an important source of system reliability in Sweden. The need for coordination adds further to the lead time and complexity of specifying a capacity mechanism design.
- **A capacity mechanism would likely be irreversible.** Once introduced, a capacity mechanism would be central to investment and other business decisions, and thus difficult to remove. It also would be a major step towards effective re-regulation of investment, as any investment decisions not supported by either subsidies or capacity payments would likely be unviable.
- **Capacity mechanisms can have complex knock-on effects.** A capacity mechanism would have a number of knock-on impacts, including implications for electricity prices, and for trade across borders with differences in capacity mechanism provisions.
- **Increasing demand-side technologies may provide an alternative**. The need for capacity mechanisms is significantly reduced if consumption can be made more flexible. Emerging technologies and business models for electricity storage, automation, and smart grids hold promise as future solutions, which should caution against rushing decisions to pay for more capacity.

As with other choices, there are benign and less good scenarios for a possible future capacity mechanism – the above concerns may be possible to overcome. However, introducing such a mechanism in a heavily contested and uncertain situation, and without resolving key underlying tensions, is much less likely to be successful. A capacity mechanism therefore cannot be an effective substitute for finding a more stable approach to the future of the Swedish electricity system.

Choosing between options requires balancing different objectives for energy policy

As noted above, in deciding on options for future market design, policymakers have three key decision frames to balance against each other: reliability and investment, cost and competitiveness, and attainment of environmental objectives. Overall, we find that the trade-off may very well be less acute than much of the current debate assumes. The following are some of the key factors that influence the choice of market design in each of these respects:

1. Reliability and investment

- The most immediate reliability concern is the abrupt and simultaneous exit of nuclear power. Market design is not the best mechanism to regulate outcomes in this case, both because lead times for changes are too long, and because the underlying problems do not arise due to flaws in the market design, but from other factors.
- Reliability can in principle always be increased with more certainty through a capacity mechanism. However, this comes at a cost. Their use should be limited to situations where there is good reason to think that an *energy-only* arrangement could not achieve enough reliability. We are not there yet, and there are alternatives; international experience shows that renewed commitment to energy-only principles can stave off emerging capacity challenges, and emerging demand-side options continue to develop.
- The strategic reserve can continue to support reliability in an energy-only market framework, but if kept in the longer term should be redesigned to be less distorting. Unlike a capacity mechanism, it could be phased out at a later date.
- Uncertainty about future policy is a major impediment to investment, and therefore to reliability. The most important factor for improving longer-term reliability therefore might be to commit to a future framework for the electricity system.
- Integration in a wider regional market is an important part of ensuring reliability. Changes to market rules and regulations to promote reliability also will be more effective if coordinated at the Nordic level. This increases the stability of the overall regulatory framework, and also creates a process to minimise unintended consequences for the important role of cross-border trade in promoting reliability.

2. Cost and competitiveness

- Subsidies for new entry of renewables are costly not primarily because renewable electricity is more expensive than other options for new supply, but because it is more expensive to build new capacity than it is to make use of existing plant. This is true regardless of whether the plant uses renewable energy sources or not.
- Such subsidies significantly affect the working of the market and increase the turnover of capacity – regardless of whether the specific support system itself is 'market-based'. Mandates for new capacity therefore also affect the ability of any given market design to perform and achieve cost-effective outcomes.
- Subsidies can result in lower prices that benefit consumers in the short to medium term. However, this occurs not because overall costs are lower, but through a short-term redistribution from producers to consumers. In the longer term, the additional costs of increasing the turnover of capacity nonetheless have to be paid for – ultimately by consumers or taxpayers.
- Even a perfectly implemented capacity mechanism entails higher costs than a continued energy-only arrangement – corresponding to the insurance premium associated with maintaining a higher level of capacity. In addition, the complexity of capacity mechanisms and uncertainty about key parameters also create a risk that costs escalate.
- A major benefit of a competitive market over regulations is the ability to foster competition between solutions. Forcing the pace of change through regulation may

mean future and emerging options are foregone. Technology and business models are changing fast, and future increased demand response, electricity storage, and other options could well prove more cost-effective than using a capacity mechanism to mandate the increased deployment of currently available technology in the near-term.

3. Environmental objectives

- Increasing renewable electricity supply in Sweden has limited climate benefits in the current Swedish market, which already is nearly fossil free. Instead, the plants exiting the market to make way for new entry already are zero-carbon.
- Renewable electricity in Sweden can in principle displace some fossil generation in other countries. However, in the scenarios we analyse this also rapidly hits diminishing returns. Substantial additional interconnection as well as higher prices in other neighbouring markets would be required for this to be viable in the longer term, and neither is assured.
- The current market design can support investment in renewable electricity, and our modelling suggests that wind power could earn sufficient revenues in the current market model once over-capacity is reduced (e.g., because demand grows) and commodity prices recover. However, no market can support investment in new capacity in a situation of over-supply – whether in renewables or other options.

A fork in the road: continued liberalised markets, or steps towards re-regulation

The choice of market design is part of a more fundamental choice about the electricity system. Broadly speaking, this could take the shape of either re-committing to a liberalised electricity market, or accepting a substantially more regulated system.

Recommitting to a liberalised electricity market would be motivated primarily by a concern for cost and competitiveness. Targeted reforms would improve the ability to ensure reliability and efficiency in new circumstances. Reduced regulatory intervention would reduce uncertainty. Longer-term, improved demand response and interconnection could further improve the functioning of the system. Investments in new capacity would be matched with longer-term growth in demand, to allow the market to adapt the capacity mix on the basis of market prices without too much distortion. Given the remaining lifetime of current capacity, turnover and entry of new generation would likely be relatively slow – not because of any market bias, but because this would be the less costly option.

Increased regulation would be motivated primarily by a desire to quickly change the capacity mix, for environmental or other reasons. This would entail continued subsidy of selected forms of new electricity production to accelerate the turnover of capacity. An *energy-only* market could continue to function in some scenarios, but in adverse conditions (large regional over-capacity, low commodity prices, and lack of political commitment), it could become necessary to introduce a capacity mechanism. If tensions become acute, further regulatory intervention might become necessary to prevent the exit of capacity or bring forward investments that suppressed energy prices could not support.

Which path is chosen depends on political preferences. It is likely that a reliable electricity system could be achieved under either outcome, albeit with very different cost implications. The main threat to reliability comes instead from uncertainty, and a mix of different, increasingly incompatible approaches. There thus is an urgent need first to take action to resolve near-term tensions, and then to commit firmly to an overall direction of travel.

Chapter 1

Introduction

Sweden has benefited from a stable and well-functioning electricity system. Competitive markets and a mature market design have achieved high reliability and cost-efficiency. In addition, Sweden finds itself in an enviable position of a power system almost entirely free of carbon-dioxide (CO_2) emissions.

Despite these successes, the electricity system now finds itself under significant pressure. New power generation capacity is entering the market through mandates and subsidy support, resulting in emerging over-supply of electricity. This, combined with low prices and new regulatory requirements, calls into question the future viability of established generation sources, notably nuclear power. Future higher shares of variable wind power creates new needs for flexibility and back-up capacity. Overall, a wide range of possible future developments are possible, but subject to significant policy uncertainty. This takes place against a backdrop of fast-paced innovation that is gradually creating new opportunities and solutions, which once available could well prove to be less costly than the current menu of options.

This combination of factors has generated a debate about electricity market design. Is the current market design fit for purpose, and able to continue to achieve a reliable and cost-effective electricity system that meets environmental and other societal goals? What are the risks and costs involved in early decommissioning of existing generation capacity to make room for new production? What reforms could make the current system more robust for future requirements? At what point might major departures from the current market design be required?

We address these question in this report. Overall, we find that there is much that can be done to ready the existing market for future needs, and that major departures are unlikely to be required other than in exceptional scenarios. To a large extent, the factors that are creating current tensions depend on policy choices. Decisions about market design therefore has to be set in a context of reducing the tensions and uncertainty that characterise overall energy policy.

Chapter 2

Winds of change in the Swedish electricity system

The principles and institutions underpinning the current electricity market design have been in operation for nearly 20 years. These include the rules, regulations and institutional arrangements that have set the parameters for how the market operates. This setup has guided investments in, and operation of, the electricity system well through a market-based design.

However, recently, existing market designs across Europe have been called into question, as a number of disruptive trends affect electricity systems. In this chapter, we introduce some of the main trends and their relevance for choices about electricity market design. A major finding is that Sweden differs in important respects from EU-countries that have opted for an increasingly more regulated approach to electricity markets.

2.1 Rapid change and a high rate of innovation in the electricity sector

The electricity sector is undergoing rapid change, with a very high rate of innovation in new technology, as well as new actors and business models. This situation places significant demands on the ability to adapt for all actors whose decisions shape the sector: companies, regulators, investors, and consumers.

First, **new technologies** are entering the market, with wind power and solar photovoltaics (PV) the most recent additions as large-scale sources of generation. Over a short period of time, the costs of these renewable sources have fallen significantly, increasing their attractiveness and market penetration. The average generation cost for new onshore wind plants fell by 30% in the period 2010-2015. The cost of solar PV declined by two-thirds over the same period and costs are approaching that of gas-fired generation in some countries.[5]

This has had significant implications for the generation options available to the Swedish electricity system. For example, a comparison of generation costs suggests that wind power is among the cheaper sources of new power in Sweden.[6] It is likely that, even without subsidies (and possibly even without a price on CO_2), wind power would be among the new generation sources selected if new generation capacity were required. (By contrast, solar photovoltaics remain significantly more costly in Swedish conditions.)

These technologies differ in important respects from traditional generation sources:

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5 International Energy Agency, *Medium-Term Renewable Energy Market Report 2015*.

6 Elforsk, 'El Från Nya Och Framtida Anläggningar 2014'; Sweco, 'Ekonomiska Förutsättningar För Skilda Kraftslag'.

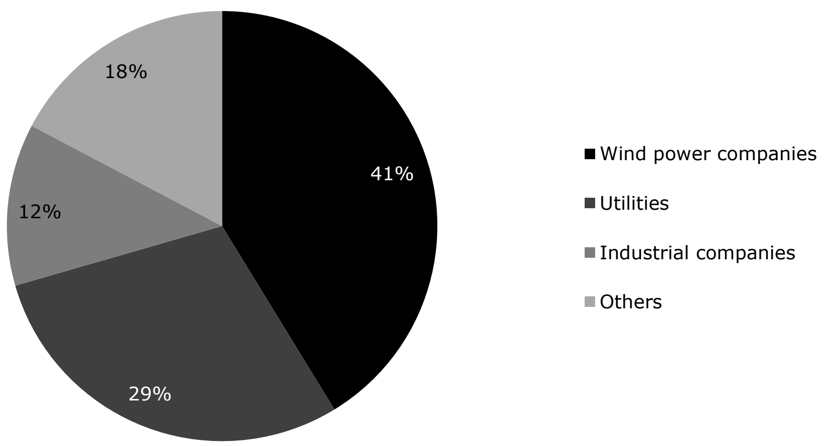
- Unlike fossil sources (but like nuclear and hydropower), costs are concentrated to the initial deployment, with no or very low operating costs thereafter.
- Generation is both inflexible and variable (weather-dependent).
- The technologies are modular and typically installed in smaller units than traditional plants.

These features affect their market participation. Once installed, wind and solar power will always bid into the market at any price above zero.

Second, **new actors** are entering the market. These bring with them new business models and financing mechanisms. The electricity sector used to be concentrated in large, often vertically integrated utility companies. Increasingly, small developers now own and operate most of the new generating capacity. Moreover, financing has moved from utilities' balance sheets to new sources, including project finance, municipal finance, institutional investors, and balance-sheet finance from industrial and other consumers.

The shift in ownership patterns is very visible in the Swedish electricity system. The 9 gigawatts (GW) of wind power added between 2013 and 2014 have a diverse ownership, with less than a third owned by traditional electric utilities (see Figure 2.1).

Figure 2.1 A diverse set of actors have invested in wind power



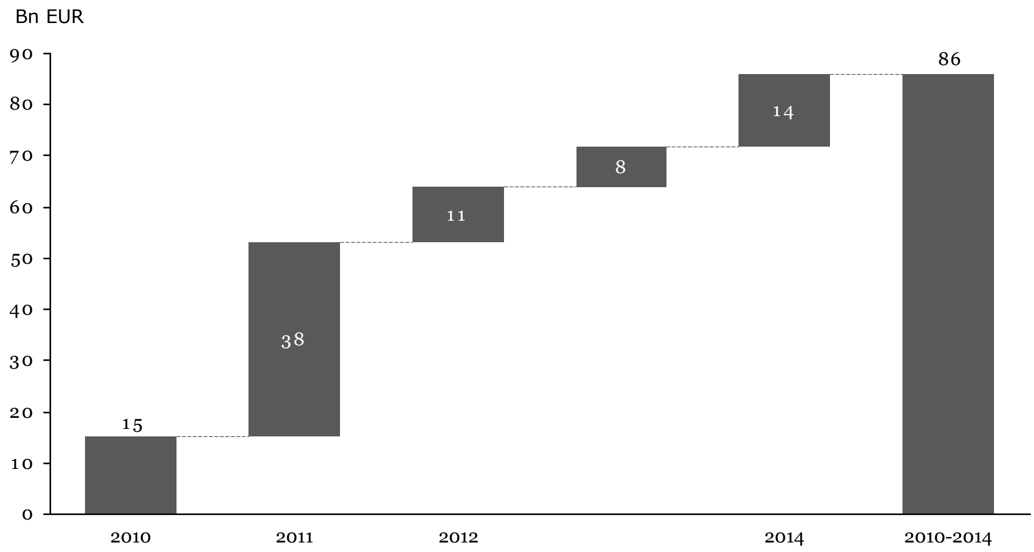
Note: Shares of Swedish wind power ownership based on production of new installations of 4.6 TWh during 2013 and 2014. "Others" includes property owners, municipalities, and households

Source: Swedish Energy Agency (2015)[7]

Meanwhile, traditional electric utilities have suffered large losses and write-downs of the value of existing generating plants (see Figure 2.2). As we discuss later on, the profitability of keeping existing generating plants operating in turn has significant implications for the reliability of the overall power system. The weak financial state of utilities also affects their capacity for investment.

7 Swedish Energy Agency, 'Vindkraftstatistik 2014 Tema: Marknadsstatistik Och Trender'.

Figure 2.2 European electric utilities have incurred large asset impairments



Note: Annual and total asset impairments among 16 European electric utilities (Centrica, CEZ, EDF, Energias De Portugal (EDP), Engie (formerly GDF Suez), E.ON, Enel, Fortum, Gas Natural, Iberdrola, RWE, Scottish & Southern (SSE), Suez Environnement, Vattenfall, Veolia Environment and Verbund), over the period 2010-2014.

Source: EY (2015)[8]

Third, the sector is becoming much more **decentralised**, and **new roles** are emerging for consumers, distribution system operators (DSOs)[9] and new market actors, and increasingly mediated by smart grid technologies that use computer-based remote control and automation to manage the balance between electricity supply and demand:

- New generation (wind and solar in particular) is often small, dispersed and connected to the distribution grid rather than the transmission grid.
- Both large and small-scale consumers are increasingly able to produce power for own consumption and delivery to network.
- Consumers are increasingly able to participate actively in the power market, blurring the lines between consumer and producer ('prosumer'). Through storage (batteries and electric vehicles) and small-scale generation, power can be sold back to the system, and through smart metres and hourly metering, the demand-side will become more responsive
- Smart grids hold the promise of significant new capabilities, ranging from managing increased distributed generation, to enabling and automating flexible demand side response.

[8] EY, 'Benchmarking European Power and Utility Asset Impairments. Testing Times Ahead'.

[9] *Distribution system operators* are entities which are responsible for operating and developing the infrastructure that distributes electricity from the transmission system (run by the TSO) to customers.

These developments also are relevant for market design. In particular, they hold the potential for a more flexible demand side, capable of responding by reducing consumption when prices increase, as well as the possibility that storage can smooth and shift consumption patterns. Both of these have long been a missing piece in improving the functioning of electricity markets.

2.2 Climate objectives has resulted in significant regulation of investment in the EU power sector

Policy to reduce the emissions of carbon-dioxide (CO_2) from electricity generation is a major source of change in the European electricity systems. At EU level and in most countries, 'road maps' for how emissions can be reduced rely to a large extent on the decarbonisation of electricity combined with the increased use of electricity for heating, transport, and industry.

This has profound implications for many power systems in the EU. For countries with high-carbon power systems, achieving targets for lower emissions will require not just a 'natural' rate of change, whereby old plants are retired at the end of their technical life, and gradually replaced by new lower-carbon sources. Replacement instead has to be accelerated: reducing the utilisation of existing polluting generation, withdrawing some plants from the market, and introducing low- or zero-carbon power in its stead.

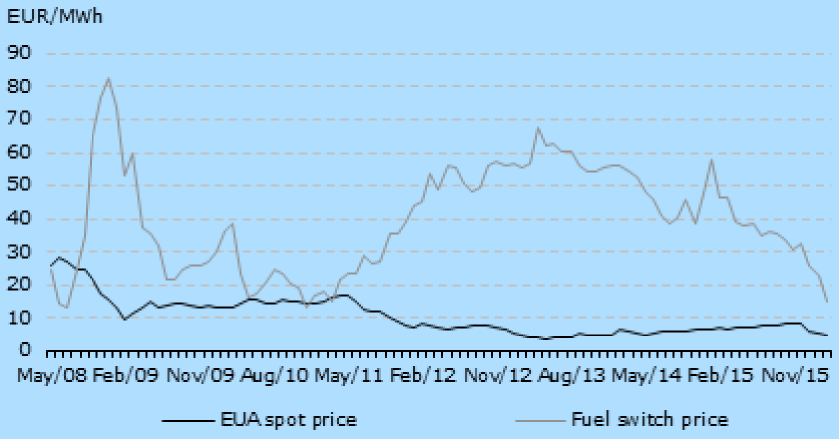
The EU emissions trading scheme (ETS) was launched in 2005 to guide this process cost-effectively. This mechanism works hand-in-hand with electricity markets. By raising the cost of CO_2-emitting plants, it would enable a different production mix, such as the reduction of generation from higher-polluting coal in favour of increased production from lower-emitting sources such as natural gas. As deeper cuts become necessary, prices would rise to the point where generation from existing fossil fuel plants becomes costlier than that from new carbon-free power, motivating new investment. A CO_2 price would result in higher electricity prices, helping trade off the cost of adding new generation capacity against opportunities to improve energy efficiency. Alongside these, a CO_2 price would enable measures to be taken not just in the electricity sector, but in other sectors covered by the cap of emissions.

In practice, however, mechanisms other than CO_2 prices have been used to force change in the electricity sector. One reason is that acceptance for high CO_2 prices has been low in Europe, not least as they would disadvantage industrial producers that face international competition from other geographies without such CO_2 prices. Other policies, such as subsidies for renewable energy have been used instead. For a given EU ETS emissions cap such policies do not reduce emissions (but simply relocate them within the overall trading scheme), albeit that they might increase the tolerance for more stringent future quotas. However, these policies have put downward pressure on the CO_2 price, even as a major recession reduced emissions in a number of sectors. Overall, the resulting lower EU ETS prices have taken a backseat role in shaping the development of the EU power sector (Box 2.1.).

Box 2.1 The EU ETS has taken a backseat role in shaping the EU electricity market

As the EU's climate policy flagship, the EU ETS was foreseen to be the main driver in the low-carbon transition including in the power sector. However, CO_2 prices that could have driven power sector change have not materialised. As an example, the fuel switch price between gas and coal has been higher than the carbon price for the past five years.

ETS prices have not induced switching from coal to gas in power generation



Note: The fuel switch price is the threshold price at which natural gas is more competitive than coal as input fuel in power generation. Gas prices are European average border import prices. Coal prices are ICE Rotterdam Coal Futures #1 (ATW1). CCGT efficiency 50%, coal efficiency 35%

There are a number of reasons for the low ETS price:

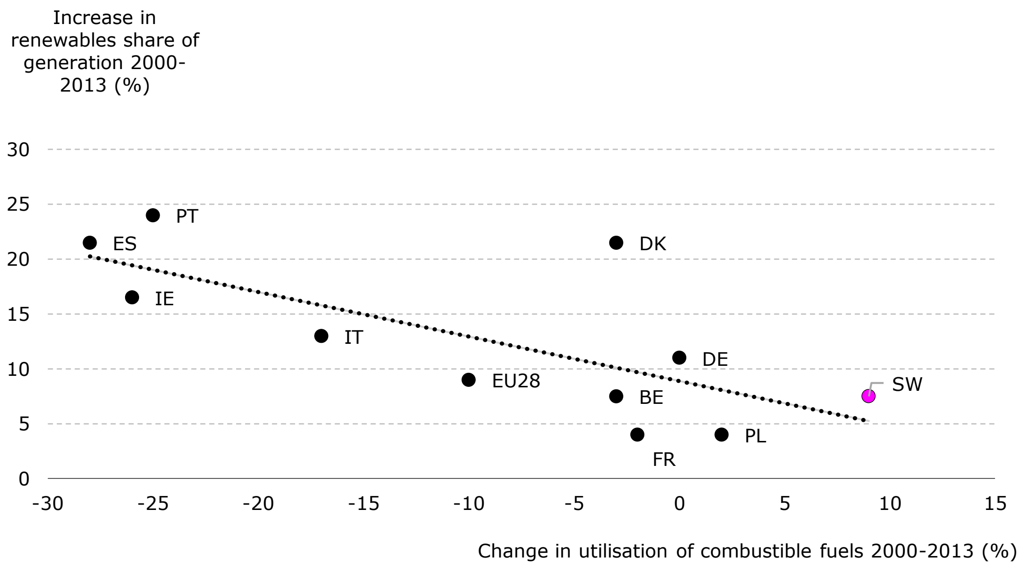
- Low demand due to the economic crisis and slow return to growth
- Competing instruments to reduce emissions such as renewable energy subsidies and energy efficiency policy
- Little faith in a stable regulatory framework to drive prices up

Source: Copenhagen Economics based on data from Platts, EEX and Quandl

Instead, the process of reshaping the EU generation mix has been driven to a large extent by policy to support renewable energy through support systems, such as feed-in tariffs (i.e., payments for delivering renewable energy to the grid) or quota systems. Production of renewable electricity in the EU grew by 80 per cent, from 414 to 744 terawatt hours (TWh), in the period 2005-14. In the same period, electricity demand in most EU countries was stagnant or even declining, as a result of structural economic change, low economic activity, and increased energy efficiency.

This combination to some extent can 'emulate' some of the outcomes of a CO_2 price: if new low-carbon generation is added to the market at a higher pace than the growth of demand, there has to be a reduction in generation from existing generation. This effect is having significant impact. Across the EU, the utilisation rate of thermal plants (dominated by coal and gas) has fallen steadily over the past decade, from around 60 per cent to 50 per cent, and with much greater declines in countries with large penetration of renewable electricity (Figure 2.3). There are exceptions: for example, in Sweden and Denmark, increasing exports have offset some of this, while in Germany increased exports, reduced production from nuclear power, and various policies have caused other generation to stay more or less constant. The key take-away nonetheless is that reduced generation from existing sources is an intended consequence of subsidies for new entry of renewable electricity. Of course, CO_2 emissions will be reduced only to the extent that the generation being pushed out has such emissions.

Figure 2.3 The entry of new renewables has led to reduced utilisation of other types of electricity production

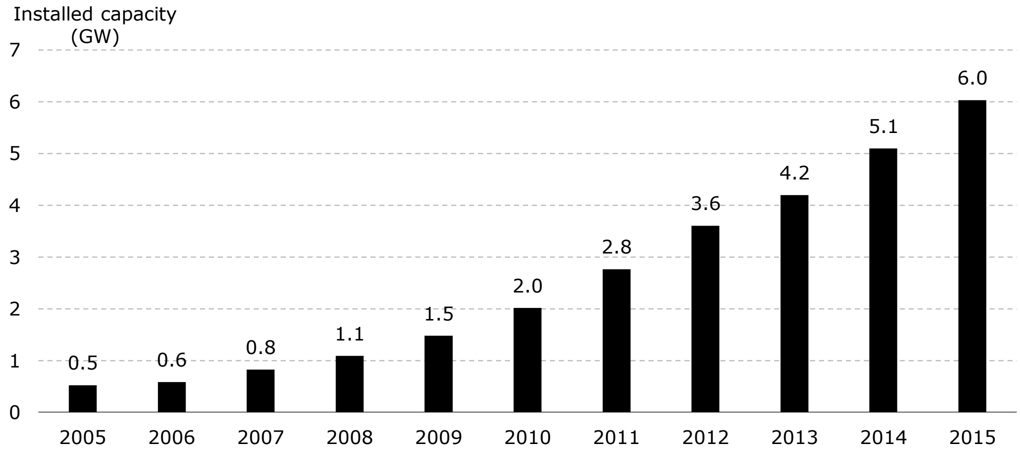


Source: European Commission (2016)[10]

Support for renewable electricity has been a major factor also in Sweden and thus the Nordic electricity market. In particular, the installed wind power capacity has increased ten-fold in the past decade, growing by 5.5 GW, driven by a quota system that sets minimum levels of total renewable electricity generation for a number of years in the future (Figure 2.4). Worldwide, only Denmark has added more production from wind power on a per-capita basis.

[10] European Commission, 'Commission Staff Working Document. European Commission Guidance for the Design of Renewables Support Schemes Accompanying the Document Communication from the Commission Delivering the Internal Market in Electricity and Making the Most of Public Intervention'.

Figure 2.4 Swedish wind power has grown rapidly

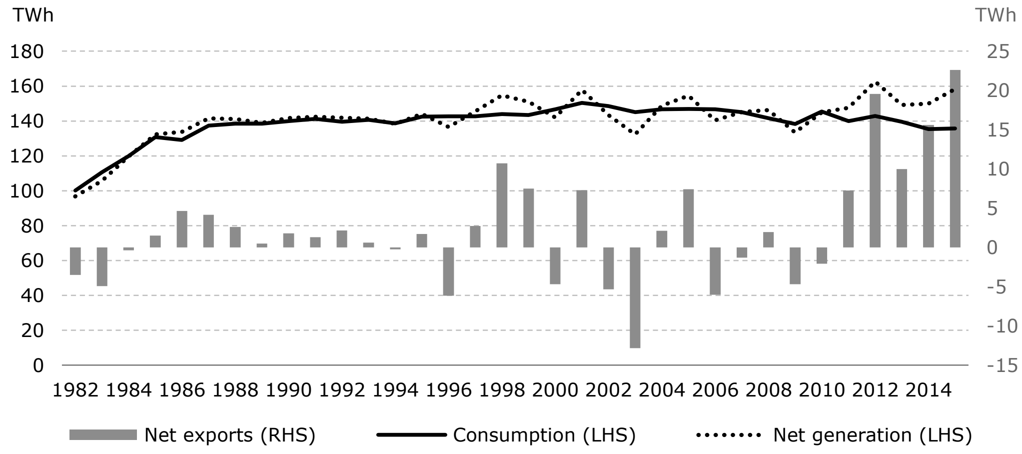


Source: Data from Swedish Energy Agency

Sweden, like much of the rest of the EU, has introduced this new generation in a situation of stagnant demand for electricity. This is in sharp contrast to other periods of increase in generation capacity; for example when the current nuclear capacity was built, Swedish electricity demand was growing at a rate of 5 percent per year, or a doubling in about 14 years.[11] To date the main impact of increased wind power has been not a reduction in generation from other sources, but an increase in net exports (Figure 2.5) and lower wholesale electricity prices. Exports in turn has depended on more efficient use of the transmission infrastructure used to transport energy within and across borders. As we discuss elsewhere in this report, however, there are reasons to believe that continued expansion of renewable electricity is now reaching levels where exports are unlikely to continue to grow, necessitating reduced production from other, existing plants in Sweden if capacity is to continue to grow faster than underlying demand. Indeed, the closure of four nuclear plants has already been brought forward in time.

[11] In total, ten nuclear reactors were taken into operation in Sweden during the period 1972-1985.

Figure 2.5 Rapid new build and stagnant demand have resulted in increasing net exports



Note: Negative exports means imports

Source: Data from Swedish Energy Agency

While Sweden has adopted renewable electricity targets much like other EU Member States, the climate benefit is much less clear in Sweden's case. The power and heat system is substantially decarbonised, with a carbon intensity lower than many other EU countries will see for decades to come. This is underscored by national Swedish 'roadmaps': unlike other EU countries, only a very marginal reduction in emissions is expected from power and heat generation.[12]

There are other potential motivations to support renewable electricity, with innovation policy and energy security those most frequently cited in relevant EU Directives.[13] Energy security – primarily concerned with reducing reliance on imported coal and gas – arguably has little applicability to Sweden. The most plausible potential candidate therefore would be that of 'learning spill-over': i.e., that the installation of additional capacity helps develop technology and other innovation to reduce future costs. The EU approach of national renewable electricity targets can be seen in part as apportioning between Member States the burden of producing such learning effects as a global common good.[14] However, it is unclear that the top-down targets now in place correspond to the true extent of such benefits, and even whether the benefits continue to be material in the case of onshore wind power in a mature market such as Sweden. As noted above, onshore wind power already is among the cheapest options for new power.

12 SOU, 'Ett Klimatpolitiskt Ramverk För Sverige. Delbetänkande Av Miljömålsberedningen'; Naturvårdsverket, 'Underlag till En Färdplan För Ett Sverige Utan Klimatutsläpp 2050'.

13 'DIRECTIVE 2009/28/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 on the Promotion of the Use of Energy from Renewable Sources and Amending and Subsequently Repealing Directives 2001/77/EC and 2003/30/EC'.

14 Neuhoff, 'Learning by Doing with Constrained Growth Rates'; Newbery, 'Market Design for a Large Share of Wind Power'.

2.3 Low power prices are challenging existing capacity and new investment

Subsidies for the addition of renewable electricity have a number of effects on the functioning of electricity markets that in turn directly influence discussions about future market design.

The first is that subsidy of new entry (regardless of whether it is renewables or not) puts downward pressure on electricity prices. Swedish power prices have fallen by two-thirds since 2010 (cf. Figure 2.6), and forward markets and projections indicate that low price levels are expected for persist for several years into the future. This is due to a number of factors, including increased over-capacity in neighbouring countries as well as falling prices for commodities and EU ETS emissions allowances. However, it also seems clear that increased over-capacity has played a major role.[15] Regardless of the precise reasons for recent low prices, as new energy capacity (with low production/operating cost) is introduced and in part paid for 'outside the market' through subsidies, power market prices are bound to decrease, a signal that no further capacity is needed. The key take-away is that subsidies for one form of electricity inevitably have implications for all other generation.

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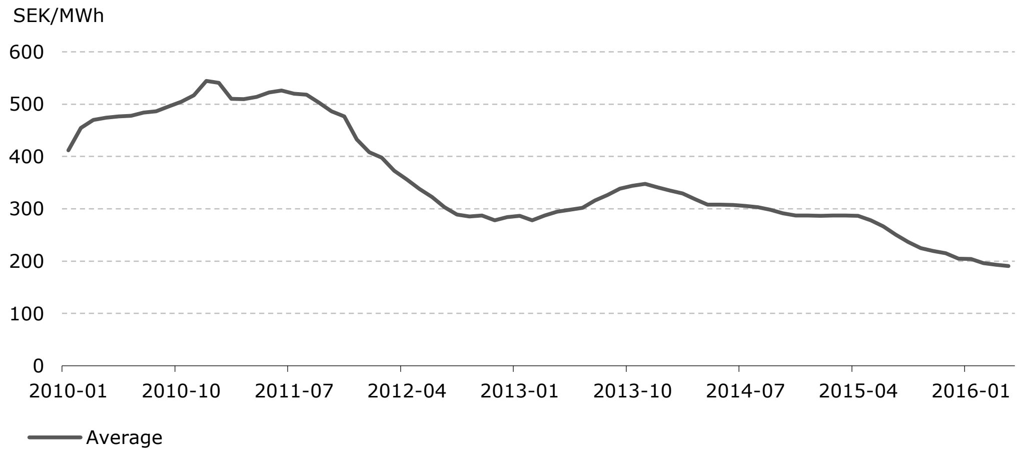
[15] See e.g. Hirth, 'Reasons for the Drop of Swedish Electricity Prices'., arguing that RES growth is the main driver while THEMA Consulting Group, 'Don't Blame the Weather! Why Power Prices Are so Low'., argues that low fossil fuel and ETS prices are the main drivers

Figure 2.6 Swedish wholesale power prices have fallen by two thirds since late 2010 and by 40% since mid-2013



Note: 12-month rolling average January 2010-April 2016 of monthly average Nord Pool Spot market prices in Sweden. Prices in nominal terms. Sweden was divided into four price areas (SE 1-4) from November 2011, the rolling average for Sweden after November 2011 is based on the unweighted average of SE1-4. The graph shows the unweighted average over the four price areas.

Source: Copenhagen Economics based on data from Nord Pool.[16]

This change in prices has no direct link to CO_2 emissions. All producers receive the same electricity price for a given hour. CO_2-free power, such as hydro- or nuclear power, is affected to the same extent as polluting coal-fired power.

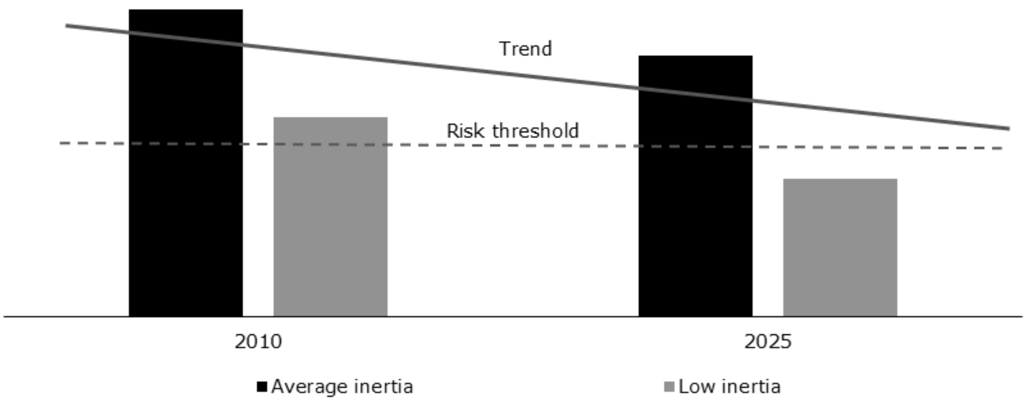
This is of immediate relevance to power generation in Sweden. In order to continue operation of the nuclear reactors beyond 2020, significant investments on the order of SEK 500-1,000 million (roughly €50-100 million) per reactor are needed over the coming five years, driven in large part by increased safety requirements. [17] The owners of the plants have stated that the business case for such investment is missing. Low expected power prices and (until recently) taxes on installed capacity corresponding to 30-40 per cent of operating costs have been key factors. Four reactors with 3 GW capacity already have announced early closure in the period 2015-2020. Of the remaining 6 reactors (another 7 GW), three have now decided to invest, but three remain undecided. Together, these 10 GW of capacity have accounted for 40% of electricity generation in recent years. Low prices therefore produce an outcome in Sweden that is quite unlike that in other EU countries: not only is the capacity withdrawing as renewables are pushed in CO_2-free, but there also is a risk of very large-scale and simultaneous exit.

In addition to the implications for costs and for adequacy (i.e., whether enough capacity remains available), the withdrawal of large amounts of nuclear capacity could have implications for a range of other aspects of system stability. Nuclear power has significant

16 Nord Pool, 'Historical Market Data'.'Historical Market Data'.
17 Sweco, 'Ekonomiska Förutsättningar För Skilda Kraftslag'.

inertia, whereas ‘asynchronous’ sources such as wind power do not. If inertia becomes too low, the electricity system can be put under significant stress in the event that a large power plant is unavailable. By some estimates, the Nordic power system could see inertia fall below acceptable levels by 2025 if the amount of nuclear power were rapidly reduced (Figure 2.7), unless other, compensating measures were taken.

Figure 2.7 Inertia in the Nordic power system could fall to low levels by 2025



Note: Inertia within the Nordic power system in 2010 and 2025. The solid line is an estimated development trend for future inertia and the dashed line is a risk threshold below which the amount of inertia is deemed unacceptable.

Source: Fingrid[18]

2.4 An increased share of wind power places new demands on capacity and flexibility

The increased entry of wind power also has implications for *flexibility*, the ability of the overall power system to respond to changes in the balance between supply and demand. All power systems have an underlying need for flexibility: demand varies significantly even within a single day (and still more from the yearly trough to peak). All power systems therefore need to be equipped to handle significant swings in overall power production through a range of mechanisms (Box 2.2.).

Even without any wind power, electricity systems therefore typically require a range of different plants. Some plants may run nearly continuously if economic conditions are favourable, but there also is a need for *peak* capacity that might operate for anything from a few hundred to just a few tens of hours per year (or still less). There also is a need for plants that can adjust output quickly. The Nordic electricity system has significant flexibility resources through its large share of hydro power. Hydro power can be a very

[18] Fingrid, ‘Electricity Market Needs Fixing – What Can We Do?’

efficient technology to rapidly ramp up/down, and in many cases also is able to operate at very low shares of the theoretical maximum output.

Electricity markets pay for flexibility chiefly through the intra-day and balancing markets. These markets are designed to allow first market participants and subsequently the TSO to adjust for imbalances – that is, deviations from the amount of power they had agreed to deliver or to consume in the day-ahead market (Box 2.3).

With an increased share of wind or solar power the need for flexibility increases. Wind production can vary significantly even on relatively short time scales, so other generation sources need to be available to step in at short notice. The swings in the *residual demand* (i.e., the demand still to be served once production from wind power is accounted for) typically are steeper than underlying demand for electricity, so there also is a need to increase and reduce output from other production faster. In addition to this flexibility, there is a need for *backup* capacity to handle situations of prolonged low output from wind power.

These needs are less novel than it might seem: electricity systems always have the need for flexibility, for some plants to run for only part of the year, for market mechanisms to pay for these services, for sufficient payment to make peaking plants with low running hours viable, and for some backup capacity to handle unforeseen events. However, with more wind power, more mid-merit and peaking plants are required, to produce when wind power is not producing but be idle when it is windy. The electricity system therefore also becomes more dependent on its ability to fully remunerate such plants not only for their running cost, but also for the cost of investment.

Box 2.2 The need for flexibility is an inherent property of electricity markets

Electricity demand varies significantly over the course of a day, and even more over a year. At the same time, demand and supply much balance at each moment. All electricity systems therefore require significant *flexibility* to vary the level of production on different timescales. In addition, the system needs to be able to handle unforeseen events, such as the sudden unavailability of a power plant or transmission line.

Ensuring the short-term balance is the core task of transmission system operators (TSOs), which can draw on several sources in the power system: supply, demand, transmission capacity, and system operations:

- Flexibility on the *supply side* is when generation technologies are capable of ramping up and down and operating at low output levels. Flexibility can differ between technologies (gas-fired plants are more flexible than coal-fired plants) but also within technologies (some coal-fired plants are more flexible than others, and some hydropower plants can be adjusted whereas others cannot). In the future, responsive distributed generation could become an important source of flexibility.
- Flexibility on the *demand side* is when demand is able to adjust when the supply-demand balance changes. In order for consumers to be flexible, two conditions must be satisfied: 1) end-user prices (or other incentives) must be available to adjust consumption when supply is scarce and wholesale prices high, and 2) end-users must have the physical/technological capability of adjusting their consumption. Both of these have historically been limited for most electricity consumers, and there is a long-standing debate on how to increase demand-side response. Elements include smart metering as well as automation and intermediation by third parties (e.g., aggregators). Increased economic viability of storage solutions would also increase flexibility, by enabling shifting of consumption over time.
- *Transmission capacity* with sufficient capacity allows access to a broad range of balancing resources, including sharing between neighbouring power systems, and smart network technologies that better optimize transmission usage.
- *Flexible system operations* are changes to market and operation practices that help extract flexibility out of the existing physical system. This includes making decisions closer to real time and improved use of wind and solar forecasting and better collaboration with neighbouring power systems.

Source: Copenhagen Economics based on NREL[19]

[19] NREL, 'Flexibility in 21st Century Power Systems'.

Box 2.3 How electricity markets pay for flexibility

Due to the specific nature of the electricity market – especially the need to balance demand and supply at every moment – electricity trading takes place over a number of different time horizons. The Swedish (and wider Nord Pool) electricity market consists of the following three market types:

The day-ahead market (operated by a market place): 24 hours before dispatch, the market makes its first allocation of electricity. In this process the common 'spot price' is determined. The day-ahead prices are formed in a coupling process that covers most European countries, taking into account available transmission capacity. The spot price in turn is used as a reference point for many financial electricity contracts that may span over much longer time periods (months to years).

The intraday market (operated by a market place): The intraday market takes place in the period after the day-ahead market has closed. No single common price is established, instead market participants trade throughout the day on which electricity is to be delivered to handle *imbalances*: discrepancies between the volumes of supply and demand agreed in the day-ahead market that arise after the day-ahead market has closed. For example, if wind projections change, or if demand unexpectedly increases, parties will use the intraday market to balance their portfolios. Like the day-ahead market, the intraday market on Nord Pool is substantially a financial market.

The balancing market (operated by the TSO): One hour before dispatch and continuously to actual dispatch, the TSO ensures that there is balance in the system by procuring additional adjustments to supply and demand (up and down regulation). The costs of these activities are allocated through the imbalance settlement mechanism. In simplified terms, if the system is in imbalance (too much or too little supply), those parties who contribute to the imbalance pay a price higher than the prevailing price of electricity for any excess demand/supply. The price premium in turn finances the operations of the TSO. In the Swedish market, wind power like other sources is responsible for its own balancing. However, many smaller participants pay larger parties to discharge this responsibility on their behalf.

Source: Copenhagen Economics based on e.g. Fingrid[20]

2.5 Dependence on regulatory decisions creates significant uncertainty

The foregoing discussion makes clear that regulatory decisions are having a major impact on the market. A well-functioning market presupposes trust in and transparency of the market framework and the regulation underpinning it. If there is uncertainty about key factors that affect the business case for an investment (e.g., taxes, market rules, mandates for new capacity), market participants may delay investment (a so-called option value of waiting); may require a higher rate of return (a risk premium), or may decide not to invest at all. Overall investment therefore can be delayed, depressed, or become more costly.

20 Fingrid, 'Electricity Market Needs Fixing – What Can We Do?'

Electricity market participants have sophisticated mechanisms for handling a range of uncertainties and market risks, such as fuel prices or weather patterns. By contrast, politically induced uncertainty can be more difficult to handle, as it typically cannot be hedged or diversified away. The current electricity market environment is facing several sources of such uncertainty, which cumulatively affect the incentives to invest in new capacity. Three stand out as particularly salient in the EU and in Sweden:

- **Changes to support schemes for renewable energy** makes future capacity and prices difficult to predict. There are at least eight different types of support schemes across EU Member States and nearly all countries have seen at least one, often more, major revision of their system over the past two decades.[21] Changes have ranged from retroactive cuts to support levels (such as in Spain in Italy), to the cancellation of existing schemes (such as in the UK and Denmark), to major changes to the principles for support (such as in Germany). What happens to support schemes in turn affects the amount of new renewables capacity that is built, with profound implications for the market as a whole.
- **Reforms of the EU ETS** also are regularly discussed, creating significant uncertainty for both market actors and governments as to the effectiveness of this instrument. ETS prices therefore also are very uncertain. Most market forecasts currently discount the possibility that reforms are likely to lead to a near-term increase in prices (Figure 2.8).
- **The political acceptance of different generation types** can also change rapidly. For example, the phase-out of nuclear plants in Germany had been agreed in 1998, so that the last plant would close in 2022. In 2009, the closure date was extended by between 8 and 14 years. However, only two years later, the accidents in Fukushima prompted the German government to phase out the plants earlier than planned.[22]

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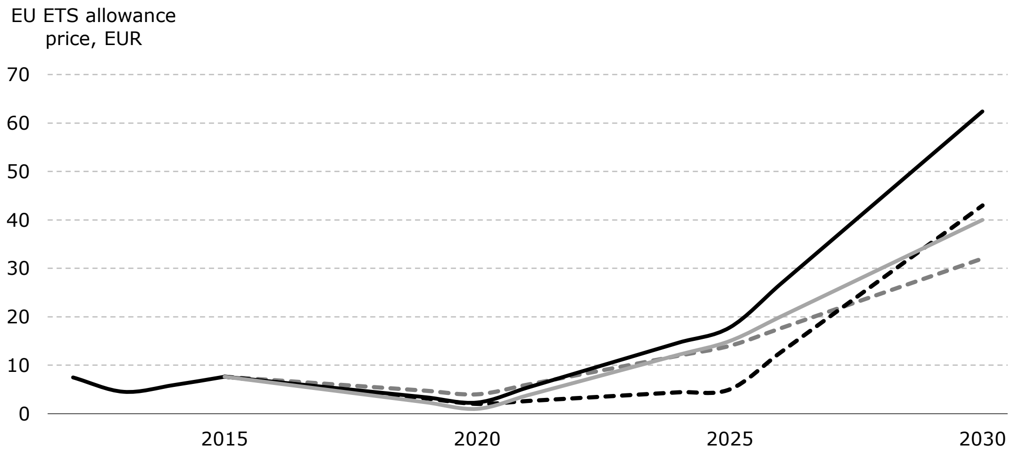
21 European Commission, 'Commission Staff Working Document. European Commission Guidance for the Design of Renewables Support Schemes Accompanying the Document Communication from the Commission Delivering the Internal Market in Electricity and Making the Most of Public Intervention'.

22 Clean Energy Wire, 'Factsheet. The History behind Germany's Nuclear Phase-Out'.

Figure 2.8 Recent forecasts of EU allowance prices show low price levels until the 2020s



Source: Copenhagen Economics based on POLES-Enerdata[23]

Many of these sources of uncertainty affect Sweden. Prior to a recent commitment to build out additional capacity to 2030, there was intense debate about the future of the current support scheme for. Positions range from no further future support, to proposals for an ambitious extension. Like in other EU countries, CO_2 prices are a significant influence on electricity prices. Different preferences for nuclear power continue to be a major source of diverging on how the power system should develop. Moreover, similar debates in neighbouring markets affect the Swedish market indirectly, as the developments in neighbouring markets are similarly uncertain.

[23] Cail, Jalard, and Alberola, 'HET 12 The Market Stability Reserve'; Sikorski, 'Carbon Market Research. The MSR'; ICIS Tschach Solutions, 'Expected Market Impact of the Proposed MSR'; Schjølset, 'The MSR: Impact on Market Balance and Price'.

Chapter 3

Options for a future Swedish market design

The trends surveyed above have prompted a number of European countries to reconsider elements of their electricity market design (see Figure 3.1).

In this chapter, we put forward two concrete and very different approaches to future market design that could be taken in the Swedish context. We focus on the issue of reliability, as this is the focus of much of current discussion of this topic.

The first option is a deepening of the current market design, based on so-called *energy-only* principles, through a number of targeted and largely incremental reforms. They have in common that they seek to strengthen and complete existing market mechanisms. The second option is to introduce a new market, for capacity rather than electricity, through a capacity remuneration mechanism (CRM).

The two approaches are not mutually incompatible in all respects, but they build on different philosophies. The first option builds on a re-commitment to the principles of competitive markets and decentralised decision making. By contrast, the second would be motivated by a belief that current markets cannot achieve important goals, notably to ensure sufficient available capacity to achieve reliability. In this view, regulatory intervention would be required to specify important parameters, including how much investment should take place.

Figure 3.1 A number of EU countries are reforming their electricity markets

Current situation	Recent and proposed reforms
France	
• Nuclear-dominated system but the future of nuclear power has been subject to political debate. Political goal of reducing nuclear share of total power generation from 75% to 50% by 2025. • Replacing lost nuclear generation with non-hydro renewables is equivalent to twice the RES 2020 target. • Past shortage of peak capacity is set to get worse.	• National peak power capacity mechanism (decentralised tradable obligation) proposed in 2015 and will be active from winter 2016-17. Plans to include cross-border participation in mechanism. • Smart meter roll-out between 2014 and 2020

Germany • Phase-out of nuclear power by 2022 through the *Energiewende* raises questions of security of supply • Coal capacity has been added in recent years as a result of earlier market conditions and free allocation of EU ETS allowances. • Rapid entry of renewable electricity (solar, wind, and biomass) has resulted in over-capacity as well as lower and less peaky prices. • Grid bottlenecks between generation in the north and demand in the south. • Some thermal power plants are held in reserve rather than closed, to safeguard system stability. • Increasing cost of supporting RES through FiT system creates political controversy	• Energy Market 2.0 reform package proposed in 2015. • Proposed introduction of a capacity reserve that will not bid in the wholesale market. • Legal stipulation that the government will not interfere in the function on the power market. • Fair competition among all flexibility options (i.e. power stations, consumers, storage and cross-border trading).
Italy • Power system dominated by fossil-fired plants (mostly gas) accounting for ~70% of total generation. Reliance on gas has led to one of Europe's highest wholesale power prices • Over-capacity due to low demand and new renewables capacity is leading to shut-down of older gas- and oil-fired plants. • A national referendum voted against nuclear power in 2011, taking this option off the table, while new coal plants would be in conflict with GHG emissions reductions targets. • Operates both a strategic reserve (interruptability scheme) and targeted capacity payments, with separate interruptability schemes for the mainland and Sicily and Sardinia. Despite this, the islands remain one of the few places in the EU with persistent reliability issues	• The targeted capacity payment is being replaced by a central buyer mechanism based on reliability options from 2017. All generating capacity meeting minimum performance criteria and not receiving other subsidies will be included, and demand side response and foreign capacity may be included in the future
Spain • Four different types of capacity payments. Payments began in 1997 and more schemes were added to compensate sources initially left out. • Strong financial incentives have resulted in large excess capacity of power at significant cost, as investments in renewable energy, CHP and gas CCGT plants increased during the past decade. Even during peak demand, only 42% of capacity is utilised (2015). • Majority of market participants does not believe the level of remuneration is sufficient to recover costs needed to keep plants on the market. • Despite a price cap in day-ahead markets of 180 EUR/MWh, consumer prices have increased rapidly due to subsidies for renewable energy, and were *c.* 15% higher than EU average in 2012.	• Focus in recent years on restoring financial stability of electricity system. • The cost of RES support was supposed to be covered by a third-party access tariff paid by consumers, but the tariff did not cover all costs and the difference has been made up through debt held by Spain's five largest energy companies (and thereby not reflected in actual electricity tariffs). The level of remuneration have been reduced since 2013, including retroactive cuts to tariffs. Wind and solar installations in 2015 were at the lowest level for 20 years. • Spain's low international interconnection capacity is being gradually addressed, with the first new international interconnector (with France) for 30 years inaugurated in 2015. The Iberian market area is coupled with the rest of Europe since 2014.
United Kingdom • Introduced capacity a mechanism in 2014 as part of the Electricity Market Reform (EMR) of 2013. Two auctions have been held for delivery in 2018/19 and 2019/20. Other features of the EMR include the introduction of contracts for difference (CfD) subsidies for RES to promote long-term price stability, long-time agreements for nuclear power, and a carbon floor-price. • Concerns about security of supply, as 20% of existing capacity (2015), mainly coal- and oil-fired plants, are to close by 2025. Construction of the GBP 18 billion-nuclear plant at Hinckley Point is supposed to provide 7% of the UK's power upon completion in 2025. • Overall, significant re-regulation, as investment decisions are determined either through capacity procurement, nuclear contracts, or RES CfD subsidies.	• Consultation in early 2016 unearthed industry concerns of too low levels of capacity procurement and payments. • In response, the UK Government has proposed to increase the amount of capacity purchased, and buy it earlier (four years ahead, rather than one year ahead). Other changes include tightening delivery incentives. • Others have criticised the capacity mechanism for over-procurement, arguing that key factors such as interconnectors are not fully accounted for in assessing the need for new generating capacity.

3.1 Where we stand: a market based on *energy-only* principles

The current Swedish market design is largely based on *energy-only principles*. These principles guide investment decisions and mechanisms to ensure reliability; how prices, trade and generation takes place; and to some extent how demand is formed (Figure 3.2).

Figure 3.2 The current Swedish market design is based on *energy-only* principles

		Energy-only principles	Deviation from energy-only principles
1	**Investment decisions and reliability**	• **Investment decisions** are taken by market actors in a competitive environment: investments are made, and plants are closed if there is no business case • **Reliability objectives** are achieved through the decisions of market actors... • **Low-carbon objectives** are achieved through the ETS...	• ... and additionally supported by a **strategic reserve** financed through a capacity payment • ... and supplemented through **targets for renewable energy** and the green certificate scheme
2	**Prices and trade**	• **Prices** are competitively determined within (Nord Pool) and between price zones and coupled markets (Nord Pool and Germany)... • **Electricity is traded** between price zones according to price differences and availability of interconnectors • **Financial trading** is widespread as a tool to hedge prices and manage risk	• **... and capped** at €3,000 / MWh and €-500 /MWh, preventing 'extreme prices'
3	**Operation and generation**	• **Generation and dispatch** is authorised by the TSO based on a competitive market allocation, implying that the cost effective plants operate • **Balancing markets** provide remuneration to flexible sources...	• ... but at times through **reserves** maintained for other purposes • ... and relying on an **imbalance price** not always giving consistent incentives
4	**Consumers and demand**	• **Competitive retail market** with free choice of provider and a variety of products and offerings...	• ... but not linked to real time whole sale prices and with limited technical possibilities for **demand responsiveness**

Source: Copenhagen Economics

Investments and reliability

A key feature of the current market design is that investment decisions are decentralised and taken by market actors. Generators in the current Nordic market receive payments only for the electricity they deliver (and possibly 'ancillary services' that they provide, see below). The price of electricity therefore needs to cover not just variable operating costs (such as fuel costs), but also allow operators to recoup the initial investment. Likewise, the amount of capacity available thus depends on investors' decisions to enter the market when there is profitable opportunity to do so. In addition, however, Sweden has also opted for a strategic reserve of power plants that receive a payment to be available in emergency situations, but which otherwise do not participate in the electricity market.

While investments are undertaken by market actors in a competitive environment, they are heavily influenced by a range of regulatory factors, including:

- Renewable energy policy: As noted, much of investment in recent years has been driven by quotas that mandate new capacity and pay for these through a certificate market. This in turn affects the electricity price, and therefore all other investment decisions.
- Capacity and property taxes that are levied on nuclear and hydro plants affect the attractiveness of investment in either existing or new capacity.
- The construction of cross-border transmission lines as well as the level of transmission charges affect investments in Sweden, as they determine the feasibility and attractiveness of exporting and importing power.

Prices and trade

Wholesale prices are determined 24 hours before dispatch through a competitive process where consumers and suppliers submit detailed bids of prices and quantities into the market. Based on a clearing process between the 12 price zones within Nord Pool and subsequently between coupled price zones elsewhere in Europe, a system price is determined for each zone. This process ensures that the market actors with the lowest offered prices produce.

For most of the hours in a year, electricity markets have more capacity than is required to meet demand. For example, in 2015, electricity demand peaked at 23.7 GW, but for three-quarters of the year it stayed below 17.5 GW; more than 6 GW of capacity therefore was idle for most of the year. When there is spare capacity, suppliers compete to generate, and prices tend to be approximately equal to the variable operating cost of the most expensive plant required to meet demand. Generators whose costs are lower than this marginal plant receive revenues in excess of their variable operating costs. These *infra-marginal rents* in turn cover some of the cost of investment. Conversely, generators whose costs exceed this level are outcompeted and do not produce in the given hour.

Price formation is not entirely unregulated, but subject to an effective price ceiling of 3,000 EUR/megawatt hour (MWh) and a price floor of -500 EUR/MWh. This price cap is harmonised at the European level since 2014. As it is a technical feature of the computer systems used, it could in principle be changed. However, the limitation is not just a technicality, but also reflects an unease among regulators to let prices rise to any, unlimited level. As we discuss below, the level of this price cap can have significant implications for the ability of an energy-only market to achieve sufficient levels of capacity.

Unlike many other commodities, electricity can only be traded within a transmission network. In some periods there is *congestion*, where the grid's capacity to move electricity from one area to another is exhausted. Increasing production in one part of the network then may have very little value (as there it cannot be transported to meet demand), while more production in another could be very valuable. In Sweden, this manifests itself through different prices in different locations. Such price differences create an important market signal: to invest in capacity in regions where it is most needed, and for investing in increased transmission capacity.

Financial trading in electricity markets is widespread. Much of the electricity volume consumed is covered months or years in advance through financial contracts. Price hedging is used to manage risks both on the generation and consumption side. The Nord Pool system spot price, the price that would prevail across the Nord Pool system if there was no congestion between price zones, is typically used as a reference price for these transactions.

Operation and generation
Based on the allocation in the wholesale market, the TSO coordinates production generators have been contracted to produce during their allocated hours. However, the exact volumes of desired consumption and feasible production can change during the 24 hours between spot price clearing and actual dispatch of electricity. An additional market, the *intra-day market*, therefore operates up to one hour before delivery of power. Additional adjustments required after that point in time are undertaken by the TSO, which operates a *balancing market*, where it procures sources that can increase or reduce their production or consumption up to the point of actual dispatch.

In order to ensure security of supply, the TSO acquires control of a variety of capacity reserves for both small-scale frequency control and more large-scale disruptions, such as the unexpected unavailability of an interconnector. The timing and pricing of dispatch from these reserves affects the resulting prices and therefore potentially also the investment conditions for market participants.

Consumers and demand
End users buy electricity at a retail price, which in addition to the wholesale price of electricity also includes charges for the transmission and distribution networks, as well as a range of taxes and fees. The retail electricity market in Sweden is deregulated, with a range of different suppliers competing for customers. These in turn offer a variety of different products and contracts (fixed in advance or variable prices, with different structure depending on the level of consumption, etc.).

A major difference between electricity markets and many other markets is that there is a disconnect between production and the demand-side. While a large number of consumers in Sweden have 'smart metering' of their consumption, most nonetheless do not have direct exposure to wholesale prices. Even if production is scarce and prices therefore rise, consumers typically do not have an incentive to reduce their consumption (even if, in principle, they would rather use less electricity than pay high prices). Current technology also means they face relatively large costs of adjusting consumption. Consumption levels therefore respond only very weakly to wholesale prices compared to the situation in other markets.

SCARCITY PRICES AND 'MISSING MONEY'

As noted above, 'infra-marginal rents', whereby lower-cost generators receive an electricity price higher than their variable operating costs, are an important mechanism for repaying the initial cost of investment for many power plants.

However, such infra-marginal rents on their own cannot completely cover generators' cost of investment. In particular, some generation capacity is required only during periods of high demand. This *peak capacity* is essential to ensure that demand can be met all times, and thus is key for a reliable electricity system. It might operate for anything from a few hundred to just a few tens of hours per year (or still less). However, as long as there is spare capacity available, peak generators will be the marginal (most expensive) plants when they actually do operate. Electricity prices therefore do not rise higher than their running costs, and they earn no or little infra-marginal rents. Without some other mechanism, their revenue would be insufficient to cover their capital costs, peaking plants would be unprofitable, and there would be insufficient capacity to ensure reliability.

In an energy-only market, this revenue gap is plugged by *scarcity prices*: periods of very high prices that arise when available supply is scarce (exhausted) – for example, either because some capacity is unavailable, interconnectors are unavailable, or demand very high. In these circumstances, electricity prices can rise significantly above the cost of generation, potentially to levels many multiples of the average price level during the year. Unlike most other product markets, it therefore is a normal feature of energy-only markets to observe long periods of moderate prices, punctuated by periods with very high price spikes.

Peak generators (and indeed all generators to some degree) depend on some degree of price spikes to cover all their investment cost. If scarcity prices are too low, or too infrequent, peak generators receive too little revenue and will not be able to stay in or enter the market. This is often referred to as a *'missing money'* problem. Much of the debate about whether energy-only markets can achieve sufficient reliability hinges on whether the problem of missing money is large – or more specifically, large enough to warrant intervention in the market through other means.

Having capacity with low utilisation is not unique to electricity markets. However, electricity differs in that demand is very unresponsive to the (wholesale) price. If demand would always adapt in scarcity situations to clear the market, there would be no missing money problem. Consumers would simply choose not to pay for very expensive electricity, and consume less, cf. Box 3.1. However, if consumers do not respond, all adjustment instead has to happen through supply. This also means that, if demand could be made more flexible, the need for scarcity pricing and potential problem with 'missing money' both are reduced. Peak plants would still need scarcity pricing to cover their costs, but there would be less need for such plants in the first place.

Box 3.1 Limited demand side flexibility creates challenges for reliability

At root, much of the concern about 'missing money' and insufficient reliability arises because electricity markets have a relatively weakly responding demand side. Unlike many other markets, there is little short-term response from electricity consumers even if prices rise to very high levels. Instead of consumers gradually reducing their consumption so that the market can clear (i.e., supply and demand brought to the same level), the decision to disconnect some consumers in periods of insufficient generation (brownouts or blackouts) has to be done by a regulating agency. Because the decision is made not by consumers but by a central authority, it also is not possible to differentiate reliability – one consumer cannot have reliability without another also enjoying the same level. This means reliability has some characteristics of a 'public good', with risk that it is under-provided by the market. This traditional concern may become less relevant over time, as 'smart' equipment makes it increasingly possible to construct contracts that include voluntary (and differentiated) curtailment of consumption of individual consumers.

In principle, disconnection should take place once prices rise above the level where consumers would prefer to be disconnected over paying for additional service. When consumers do not express this directly, regulators can define a "value of lost load" (VOLL) – a technical term for the relatively mundane idea that that consumers are not prepared to pay any price, no matter how high, for continued access to electricity. If prices are allowed to reach the level of VOLL during scarcity events, an efficient level of peak capacity can in principle be supported. Capacity that could only be supported by prices higher than VOLL represents 'too much' reliability, in the sense that it costs more to provide than the value it actually provides to consumers. Conversely, however, if prices are prevented from reaching the level of VOLL, less investment will take place, and consumers risk being disconnected (brownouts or blackouts) even though they might have preferred to pay more to avoid it.

Various factors can prevent effective scarcity pricing from emerging. For a start, the very idea of scarcity pricing can be controversial. Paying a price (say) 50-100 times higher than 'normal' can seem like a market *not* working well, and a sign that consumers are being exploited (Box 3.2). Further, there may also be fears that high prices result from poor competition rather than genuine scarcity, and that the market therefore should be subjected to enforcement of competition rules. These also are key reasons why prices are capped. Even without an actual regulated cap, the perceived *threat* of regulatory intervention could prevent prices from rising.

Box 3.2 Price spikes in 2010 proved controversial

In December 2010, Sweden saw a number of price spikes. Prices rose to 1,000-2,000 SEK/MWh during several hours, compared to normal levels of 400-500 SEK/MWh. A number of unusual circumstances contributed to this situation:[24]

- Maintenance of nuclear reactors meant some capacity was unavailable
- Low water reservoir levels limited available hydropower
- Several transmission lines to other countries were unavailable
- Cold weather meant that demand was unusually high

The situation engendered a lot of debate and media attention. Some prominent politicians and consumer groups suggested that the price spikes showed the market was not working well and should be reformed. Some suggested that there was a need to investigate whether high prices resulted from market manipulation.[25] On the other hand, the heads of the leading authorities in Sweden all jointly stated that these price spikes were in fact a sign the market was in fact working well.[26]

Another reason that scarcity prices might be insufficient is that tight supply conditions often are associated with so-called *out-of-market operations* by the transmissions system operator. These span a number of activities to procure reserves of various types, including to maintain frequency, to manage grids, or handle unforeseen events that cannot readily be handled in energy markets. Such actions intervene in production decisions, but they are not funded through electricity prices. Unless they are carefully delineated and managed, there therefore is a risk that they influence the market, including by preventing prices from rising to the levels that would be needed to support investment. The clearest example of out-of-market intervention in Sweden is the strategic reserve, which is brought into the market if it is thought that existing capacity will not be sufficient to prevent a blackout.

3.2 Six targeted reforms to strengthen the current market design

A major take-away from the above description is that the current market design already contains a number of mechanisms to handle reliability: payment for investment costs, remuneration for flexibility, support for plants with low running hours, etc. are not *qualitatively* new phenomena. They are features of all electricity markets. The current market design already includes such mechanisms.

However, the discussion also made clear that a number of factors can limit or interfere with these mechanisms. In this section we present a number of proposals for how the current market designed could be strengthened. Figure 3.3 provides a summary.

We focus on proposals related to reliability, as this is the key issue dominating discussion and proposals for changes to market design in Sweden. We deliberately include not just

24 Copenhagen Economics, 'Så Fungerar Det På Elmarknaden. Analys Av Pristopparna I December 2010| Mars 2011'.
25 Fridolfsson and Tangerås, '"Priserna På Elmarknaden Måste Tåla En Granskning"'.
26 Dagens Nyheter, '"Tillfälliga Pristoppar Visar Att Elmarknaden Fungerar"'.'"Tillfälliga Pristoppar Visar Att Elmarknaden Fungerar"'.

incremental and small changes, but also proposals that may take significant effort – in some cases, including approval and coordination at Nordic or even EU-level. (For all that, the proposals all represent less of a departure than the introduction of a separate capacity mechanism, the topic of the next section.)

The impact of each proposal would need further elaboration and investigation. The point here is to show how increased, rather than less, reliance on market mechanisms could help address some emerging and possible future challenges. As important as the technical details is the cumulative signal a set of reforms would convey: a recommitment to the principles underlying the current market design, but adapted to new circumstances.

Finally, the proposals do not include suggestions for the taxes, subsidies, standards, or mandates for particular technologies. As discussed, these can in fact be of deciding importance for the functioning of the electricity market. However, they are not elements of market design as we define it here, but instead elements that influence how different market designs might perform.

Figure 3.3 Possible reforms to strengthen the current market

1 Define a reliability standard

- Agree on an official reliability standard based on economic principles and linked to VOLL
- Incorporate standard in TSO operations and market design

2 Reduce distortions caused by the strategic reserve

- Reduce direct crowding out by changing operation
- Reduce distortion by pricing the reserve at the maximum price
- Reduce indirect crowding out by limiting market re-entry
- Coordinate the strategic reserve across Nordic countries
- Reduce uncertainty by clarifying the future status of the reserve

3 Strengthen confidence and scarcity pricing

- Raise the price cap to (a level closer to) VOLL
- Ensure institutional anchoring and precommitment
- Clarify market oversight and competition law
- Support mechanisms to mitigate consumer price risk
- Investigate the option of introducing a scarcity adder

4 Improve intraday and balancing markets

- Reduce time to gate closure and trading frequency
- Introduce new products for capabilities and system services
- Review balancing settlement procedures

5 Stimulate demand flexibility

- Support development of demand response infrastructure
- Review conditions for demand-side participation in all relevant markets
- Review price incentives created by grid tariffs and taxation

6 Improve conditions for infrastructure investment and trade

- Harmonise grid tariffs with neighbouring countries
- Evolve price areas in response to changing conditions
- Consider flow-based market coupling
- Reduce lead times for investments in generation plant and grid infrastructure

DEFINE A RELIABILITY STANDARD

The Swedish discussion about the electricity system currently is preoccupied with the issue of reliability. Nonetheless, current policy discussion lacks a framework to characterise what level of reliability is desirable. This makes it difficult to conduct constructive discussions about what, if any, changes to market design are required. As a first step, Sweden therefore could introduce an official standard for reliability, against which the power system's performance can be measured.

Such a standard would serve as a transparent way to highlight how reliability interacts with other objectives. It would serve as a guiding principle for decisions about market design, such as the size, scope, or timing for possible phasing out of the strategic reserve, or design parameters such as the maximum price in wholesale electricity markets. It also could guide the mandates given to key actors, notably the system operator *Svenska kraftnät*. In defining such a standard, Sweden would follow several other countries, including France, Ireland, and the United Kingdom (Box 3.3). A reliability standard need not be a prelude to a capacity mechanism; on the contrary, it can serve to properly assess whether such a mechanism or any other measures are in fact warranted.

The importance placed on reliability ultimately is a political decision, and has to be made through the political process. From an economic point of view, it is desirable that a definition incorporates a view on the *value of lost load* (VOLL): the value that consumers place on avoiding involuntary interruption to supply.

Box 3.3 A growing number of countries are defining reliability standards based on economic principles

A number of countries have defined reliability standards to guide decisions about market design and operational decisions by TSOs. One measure is the *Loss of Load Expectancy* (LOLE), expressed as the expected number of hours per year during which a 'loss of load event' occurs. However, this measure does not account for *how much* of the market is affected – clearly a disruption to the whole population is worse than a more limited event. A better measure in this regard is the *Expected Energy Unserved* (EEU), measured in energy units.[27]

The emerging European norm is to use LOLE. For example, the UK uses a LOLE of 3 hours per year, derived from an estimate of VOLL and the cost of new entry. LOLE-based standards also used in France (3h) the Netherlands (4h), and Ireland (8h). It also is used in PJM and some other US markets.

The Australia National Electricity Market (NEM) is unique in its use of EEU, set to 0.002% per year. The standard is set by an independent Reliability Panel and derived from an estimate of VOLL.

A simpler approach is *de-rated capacity margins*, which is used by some TSOs to assess reliability. This approach consists of taking into account each plant's likely availability during peak demand and adding the total available 'de-rated' capacity. For example, *Svenska kraftnät* gives wind power a de-rated capacity of 11% of nameplate capacity during the winter, and nuclear power a 90% rating.[28] However, this approach has some limitations. In particular, it does not account for co-variations of events and it becomes increasingly unsuitable as the amount of variable generation increases (and the actual capacity margin therefore varies more year-on-year).

Source: IEA; AEMC; DECC; Eurelectrics; Svenska kraftnät[29]

[27] Eurelectric, 'Capacity Mechanisms in the New Market Design. EURELECTRIC's Views'.
[28] Svenska Kraftnät, 'Kraftbalansen På Den Svenska Elmarknaden Vintrarna 2012/2013 Och 2013/2014'.
[29] AEMC, 'Fact Sheet: The NEM Reliability Standard'; IEA, 'Repowering Markets'; DECC, 'Electricity Generation Costs 2013'.

MAKE THE STRATEGIC RESERVE LESS DISTORTING

The current strategic reserve (SR) has a number of features that risk distorting the electricity market. In particular, there is a risk that the presence of the reserve undermines scarcity pricing and deters investment in capacity (or maintenance of existing capacity). This in turn could reduce rather than increases long-term reliability. For this reason, The Swedish Energy Markets Inspectorate (*Energimarknadsinspektionen*) and others have long called for the reserve to be phased out.[30]

For all this, the SR has has been in place for more than 15 years, and it is likely that it will remain a feature of the Swedish electricity market for another decade. A large number of Swedish stakeholders see a need for a continued SR[31]. It therefore would be more stable not to treat it as a temporary measure, but instead clarify its status; reduce any distortions it has on the electricity market; and increase confidence that its intended use is consistent with relevant rules, including EU State Aid requirements.

There are a number of reforms to the SR that could reduce its impact on the market: 1) reduce direct crowding out, 2) reduce distortion of prices, 3) reduce indirect crowding out, and 4) limit uncertainty.

1. Reduce direct crowding out by activating the reserve only in emergencies

The reserve has been activated a number of times even when commercial capacity has been available to serve the market.[32] The first step therefore is to provide credible signals that procedures will be reformed to prevent future such occurrences, which in any case are against current rules guiding the reserve. A more intricate issue is to avoid the activation of the reserve for reasons of grid congestion.

2. Reduce distortion of prices by pricing the reserve at the maximum price

Under current rules, the SR is activated at the same price as the highest commercial bid (plus a small adder). This creates a risk of distortion. The very fact that the SR is activated is a sign that higher prices could be needed to trigger additional investment. Yet once the reserve is activated, these prices are prevented from occurring. To remove this distortion, a simple option is to activate the reserve only at the level of the price cap in the market. This would reassure investors that the future activation of the reserve never affects price levels. This design has precedence, including in the Belgian reserve, and in the proposed Danish reserve.

3. Reduce indirect crowding out by limiting market re-entry

To avoid the SR undermining investment (and thus long-term reliability), it must be separated from the commercial electricity market. Under current rules, capacity participating in the reserve therefore cannot also participate in the electricity market. This is a key condition: activating the reserve would otherwise withdraw capacity from the commercial market, undermining rather than improving reliability. However, given that the SR is no longer a temporary measure, it is necessary to consider the evolution of the reserve over time. A potential investor in new capacity might ask whether some of the

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30 Swedish Energy Markets Inspectorate, 'Effektfrågan – Behövs En Centralt Upphandlas Effektreserv?'

31 Government Offices of Sweden, 'Remiss av utkast till förordning om effektreserv med konsekvensanalys'.

32 Svenska Kraftnät, 'Kraftbalansen På Den Svenska Elmarknaden Vintrarna 2012/2013 Och 2013/2014'.

capacity now withheld from the market could re-enter it at a later stage, and therefore undermine its own case for market entry. The cleanest solution would be to introduce a condition that capacity that participates in the reserve loses the right to participate in the market not only during the current year, but also during future years. This is the proposed design for the German strategic reserve.[33] However, such a change would require careful evaluation.

4. Coordinate the strategic reserve across Nordic countries
If the strategic reserve is to be kept as a long-term market feature there is a strong case for coordinating across the Nordic region. Finland already has a strategic reserve, while Denmark is considering introducing one as a temporary measure. Keeping separate spare capacity in each country is much less efficient than pool reserves in the region as a whole. To the extent the reserve interferes with market functioning, decisions in one country also can affect investment decisions and therefore reliability in another. For these reasons it would be preferable to coordinate the implementation of reserves across countries.

5. Reduce uncertainty by clarifying the future status of the reserve
Like other uncertainty about the future rules of the electricity market, the uncertain status of the SR makes planning for new investment more difficult. It therefore would be desirable to clarify, to the extent feasible, the future intended scope and role of the reserve. This should include clarity about the conformity of an extended reserve with EU State Aid rules. More fundamentally, the presence and continual revision of the SR sends a signal to the market about the confidence in the current arrangements. There is a need to 'draw a line' and make clear to market participants what role the SR is intended to have among the many factors that enable sufficient future reliability, not least private investment supported by scarcity pricing.

IMPROVE CONFIDENCE IN SCARCITY PRICING

As noted, a key challenge for an energy-only market is to create enough confidence in scarcity pricing: periods of high prices that can pay for the cost of investing in and maintaining capacity required to meet peaks in demand. With increasing variable production and generally depressed price levels, effective scarcity pricing becomes all the more important. If investment to ensure reliability is to take place on this basis, market participants need to know that, if conditions arise where new investment is required, the market design as well as overall institutional commitment exist to allow it to happen. Proposals to improve scarcity pricing must be a long-term project: a process of gradual reform, and in dialogue with other countries.

We propose five mechanisms that can help improve this: 1) gradually raise the price cap, 2) ensure institutional backing, 3) clarify market oversight and competition law, 4) support mechanisms to mitigate consumer price risk, and 5) consider the option of a scarcity adder.

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33 Federal Ministry for Economic Affairs and Energy (BMWi), 'An Electricity Market for Germany's Energy Transition Discussion Paper'.

1. Raise the price cap to (a level closer to) VOLL

Current Nord Pool rules follow EU-wide systems that prevent prices from rising above 3,000 EUR/MWh in the day-ahead market, and 5,000 EUR/MWh in the intraday market. Although Nord Pool prices have not hit these thresholds to date, in a future situation of increased price volatility, these risk being too low.

The current level of the current price cap is low compared to other energy-only-markets. For example, the Australian National Electricity Market (NEM) has a price cap of 9,000 EUR/MWh (13,800 AUD/MWh), while the Texas electricity market has a price cap of 8,000 EUR/MWh (9,000 USD/MWh). The current Nord Pool cap also is much lower than the values attributed to VOLL in recent assessment. Many international examples use higher levels still. For example, capacity market regulations in the UK were derived using a VOLL as high as 22,000 EUR/MWh (17,000 GBP/MWh).[34]

Raising price caps may be controversial. It may help if it is accompanied by rules that limit persistent, high scarcity pricing, a feature of both the Australian and Texas's ERCOT markets.[35]

2. Ensure institutional anchoring and commitment

A common argument against allowing high prices is that they have poor political and popular acceptance. No matter how good the underlying logic, it is counterintuitive to many stakeholders that electricity normally priced at (say) less than 50 EUR/MWh should reach levels perhaps 100 times higher in some periods.

A guard against this is to ensure strong institutional anchoring and commitment that periods of high prices are considered normal. For example, during the last period of high prices in 2009-10, the three directors general of the key energy authorities jointly issued a statement supporting the current market mechanism.[36] Steps to increase offer caps, and more generally to give scarcity pricing a key role in future functioning of the market, would require that commitment of this type continues to be strong. Institutional dialogue and agreement therefore is an important step in the process

3. Clarify market oversight and competition law

A reliance on scarcity prices, especially under high price caps, depends on confidence that the market is working well overall and under conditions of effective competition. If competition between generators does not work well, there is a risk that price spikes arise not because capacity is genuinely scarce, but because energy suppliers act strategically to increase the price of electricity, to the detriment of consumers. The dilemma is that it might be difficult to ascertain whether or not a particular pattern of prices results from legitimate scarcity pricing, or is the result of market power. To date, a large number of

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34 DECC, 'Electricity Generation Costs 2013'.

35 For example, in the Australian NEM, if the average price during a seven day period exceeds a trigger threshold of c. 400 EUR/MWh (600 AUS/MWh), prices are capped at a level of 200 EUR/MWh (300 AUS/MWh) until the average price during the previous week falls below the trigger threshold again. See: Australian Energy Market Operator, 'Operation of the Administered Price Provisions in the National Electricity Market'.

36 Dagens Nyheter, '"Tillfälliga Pristoppar Visar Att Elmarknaden Fungerar"'.'"Tillfälliga Pristoppar Visar Att Elmarknaden Fungerar"'.

studies give a weight of evidence against any problem with competition in the market.[37] This should give confidence that scarcity pricing can in fact be relied on.

Competition authorities cannot (and arguably should not) provide any ex-ante guarantee not to investigate or intervene in markets. Nonetheless, confidence can increase further with better oversight. This was clear during 2009-10, when some questioned whether prices in fact arose due to strategic withholding of capacity and pointed out that increased transparency and clarity about market oversight could help settle such questions.[38] Several international markets, notably in the United States, have much more intensive, real-time monitoring of bids.[39] Continuous oversight with clear rules that are defined in advance can increase confidence among all market participants that there is less risk of ad-hoc intervention.

4. Support mechanisms to mitigate consumer price risk

Tolerance for higher prices during price spikes increases when consumers have effective methods to protect themselves from the short-term financial consequences. An effective demand side complemented by a financial market therefore is a key complement to protect consumer interests. During the 2009/10 price spikes, a large share of customers in fact were shielded from the increase in prices through their long-term contracts for electricity.[40]

On the demand side, changing consumption patterns is the key mechanism, and can be developed further on the basis of hourly metering. Likewise, it is possible to keep incentives for investment in energy storage without exposing customers to price risk directly. Industrial customers similarly can use financial markets to keep exposure to price variations only at the margin, rather than for the bulk of consumption, and can also use physical hedging (investment in own production) to mitigate risk.

5. Investigate the option of introducing a scarcity adder

Another mechanism to consider is to actively stimulate scarcity pricing. Under current market arrangements, prices rise to levels determined by bids to meet an essentially fixed level of demand. Some market designs have taken steps to augment these price levels by an "adder" that progressively increases the market price in real-time as the operating reserves available to the system fall below a certain level (and the risk of an interruption of service thus increases). The arrangement is intended to compensate for the missing participation of the demand side in the market, which is one of the main reasons why short-term prices could be inadequate.

Such a step should not be taken lightly: it constitutes a significant administrative intervention. However, if careful analysis found that insufficient scarcity prices led to a low level of reliability, it is a step that may well be preferable to more far-reaching interventions, including capacity remuneration mechanisms. Apart from anything else, such adders create an effective pre-commitment that the relevant regulators accept scarcity pricing in circumstances where it is warranted. It therefore strengthens points 2

37 Fridolfsson and Tangerås, 'Market Power in the Nordic Electricity Wholesale Market'.
38 Fridolfsson and Tangerås, '"Priserna På Elmarknaden Måste Tåla En Granskning"'.
39 Damsgaard and Hollmén, 'Marknadsövervakning På Den Nordiska Elmarknaden'.
40 Copenhagen Economics, 'Så Fungerar Det På Elmarknaden. Analys Av Pristopparna I December 2010| Mars 2011'.

and 3 above, on the importance of creating a norm of institutional backing for scarcity pricing. Texas and several other US markets provide precedents for the use of such adder systems.

IMPROVE THE FUNCTIONING OF INTRADAY AND BALANCING MARKETS

The intraday and balancing markets are the key mechanism for the remuneration of flexibility, and by extension for financing the various capabilities and services the overall electricity system needs to balance supply and demand. This becomes increasingly important as the amount of variable electricity (not least wind power) increases, and there is a case for revisiting some of the market arrangements.

We identify potential changes in three areas: 1) the timing of market closure, 2) the definition of products for system services, and 3) the workings of the balancing settlement mechanism.

1. Reduce time to gate closure and length of trading intervals

All electricity markets have a point at which trading stops for the subsequent delivery of electricity, referred to as 'gate closure'. For intraday trading, this currently occurs one hour before delivery. Likewise, bids for production and consumption are denominated in hourly intervals. Events that affect the balance of supply and demand after gate closure, and variations that may take place with a higher frequency than one hour, therefore cannot be traded by market participants, but must be handled by the TSO through the balancing market and out-of-market operations.

Several other electricity markets have adapted to the need for increased flexibility by reducing gate closure times and increasing the time resolution of trading blocks. For example, the German EEX market trades in intervals of 15 minutes. Similar reforms could be considered for the Nord Pool *Elbas* intraday market. The purpose would be to give market participants further opportunity to reduce imbalances without the need for regulatory intervention.

There are several other options that could be considered. One is to reduce the time lag of trading in balancing markets to improve the chances of efficient mobilisation of resources. More far-reaching steps could include shorter trading intervals in the day-ahead market; a switch to a closing auction in intraday markets; or gate closure as close as 5 minutes before delivery (as in several U.S. markets). Each of these have their advantages and disadvantages, not least through increased complexity. Some also could have implications for other aspects of coordinating the electricity system, e.g., through the role that day-ahead markets have in enabling financial markets.

We do not evaluate these further in this report. The generic point nonetheless is that there are several options for more sophisticated markets for flexibility that already are demonstrated in other electricity markets, and which can be adopted if system flexibility becomes scarce.

2. Introduce new products for capabilities and system services

Maintaining security of supply requires that the system operator has access to a range of ‘ancillary services’: functions that the TSO requires in order to guarantee system security. These are very specific and often highly technical requirements, including the ability to ‘restart’ the electricity grid in the event of a blackout, automatic frequency response that can be activated within seconds, and spinning reserves to provide additional energy at short notice.

Some of these services, such as frequency control, already are directly procured by the TSO. However, many others are provided implicitly; i.e., they are not contracted and paid for, but are mandated through technical requirements on some generators (network codes), or arise automatically because some technologies have intrinsic characteristics that benefit the system (we mentioned inertia as one such property in the previous section). With an increasing diversity of sources, and especially with the introduction of greater shares of wind and solar power, generators will vary much more in the services they provide. If some products and services are valuable, but not paid for, there is a risk that they are not provided to the extent the system requires.

One option therefore is to introduce a more explicit market for important system services. This will help ensure that decisions to invest in or operate particular technologies take into account the value they provide to the system as a whole. Ireland provides an example of an increasingly sophisticated ancillary services market, intended precisely to ensure that all important services continue to be provided as the share of wind power grows, and to increase the share of such ‘asynchronous’ generation that the grid can bear (Box 3.4). It also is worth considering whether markets for system services (and particularly balancing services) could be based more on longer-term contracts. This would reduce risk and provide a steadier stream of revenues for providers of such services.

Ancillary services thus provide another example of the potential to increase the use of market mechanisms in response to new challenges posed by changes in the power system. Like with changes to gate closure or trading intervals, they entail a trade-off between complexity and the benefits of better-functioning markets, but illustrate that a range of further market developments are possible if the system faces additional challenges.

Box 3.4 The Ireland DS3 programme is at the forefront of defining new markets for system services

In order to reach 70% penetration of intermittent energy sources in the electricity system, Ireland decided to adapt its strategy for system services in order to meet the technical needs of the system in 2020. The SEM Committee concluded that there is clear evidence that enhanced system services are required in order to maintain a secure and reliable electricity system under conditions of high wind penetration".

Concretely, the proposal was to double the number of system services from seven to fourteen. In addition a market-based approach was proposed to determine remuneration for these services.

Source: SEM Committee[41]

3. Review balancing settlement procedures

Current Nord Pool rules follow the principle that parties who cause imbalances between supply and demand (because their production or consumption deviates from the plans they had announced) bear the costs of making the adjustments required to keep the system in balance. Thus a generator who produces less than it had announced in a situation where the system is short of power, has to pay an 'imbalance price' for the additional power that needs to be procured. The underlying idea is that these incentives should enable TSOs to plan ahead, and prices reflect the cost of bringing other generators online at short notice.

However, while the current model ensures that all parties with balancing responsibility manage their own portfolio, it does not always provide an incentive to contribute to the system as a whole. For example, if additional power is required, producers who already participate in the market and who could increase their output do not receive the imbalance price (but the market price).

In addition, the current mechanism means that demand has weaker incentives to be in balance than does supply. This can contribute to shortages in the day-ahead markets and also reduce the use of intraday markets to eliminate imbalance positions.

STIMULATE DEMAND FLEXIBILITY

It has long been recognised that electricity markets would work better with a greater degree of demand flexibility. This is true regardless of the level of variable renewables, but becomes still more important as the share of such technologies increases.

There are several barriers to achieving a flexible demand side, from lack of infrastructure, to potential regulatory barriers for demand aggregators to establish themselves in the

41 SEM Committee, 'Single Electricity Market Committee DS3 System Services Procurement Design SEM Committee Consultation'.

market place. Large-scale improvement in demand flexibility might be dependent on factors that are still some way off, including further technological development and adoption as well as norm shifts among consumers. There nonetheless are some potential reforms that could be explored even in the near-term.

1. Support development of demand response infrastructure
This includes the capabilities of measuring consumption at a sufficiently granular level, but also more elaborate infrastructure such as data exchange platforms and interoperable data standards not just for billing purposes but also for collection of data relevant for operating functions such as automated household appliances or electric vehicles. On the regulatory side, conditions for third party aggregators could be reviewed with a view to removing barriers to entry. Approaches could range from standards to full support programmes for technology adoption.

2. Review conditions for demand-side participation in relevant markets
The requirements for new forms of demand flexibility in intraday and balancing market vary by source. Current conditions and specifications have been developed and refined primarily with supply resources in mind. As new technical options become available, there is a need to review the rules, including participation by electrical storage.

3. Review price incentives created by grid tariffs and taxation
Incentives for demand response will be stronger with a more direct link between wholesale electricity prices and consumption. For example, a transparent, time based network tariff would signal the underlying costs to the grid more clearly. It therefore could also convey a clearer message of the benefit of reducing demand during peak periods.

INCREASE OPPORTUNITIES FOR TRADE AND INFRASTRUCTURE INVESTMENT

Trade in electricity has at times been controversial, as it can have large distributional effects. When Sweden had lower electricity prices than neighbouring countries, increasing the capacity of cross-border interconnectors could lead to higher costs for Swedish consumers, albeit that there was a corresponding benefit to producers. However, trade in electricity will become increasingly important with a larger share of variable renewable energy, both to smooth variations in output, and to make flexible resources available to a wider area.

We put forward three potential areas of action to promote the continued integration of the Swedish electricity system with its neighbours: 1) harmonise grid tariffs, 2) avoid divergence in market design, and 3) evolve price areas as conditions change.

1. Harmonise grid tariffs
Swedish grid tariffs, the tariffs charged by the TSO to cover costs related to the transmission grid, have a number of features that may cause tensions in the future. As the capacity balance in southern Sweden weakens and more variable capacity is added to the system, Sweden potentially becomes more dependent on imports to balance the overall

system. The current charges are higher than in other countries, and also based on capacity rather than on production. This can disadvantage generation in Sweden relative to neighbouring countries, and can be especially disadvantageous for capacity with low load factors (such as wind power or peaking plant).

2. Avoid divergence in market design

Considerable effort has gone into ensuring that European electricity markets are harmonised to the extent that they can be coupled and enable trade across countries. The Nordic region is still more integrated, with close collaboration between countries. As changes to market design are considered across the region, it therefore becomes especially important to avoid divergences that have large effects on the benefits from trade. Many parts of market design already have strong processes to harmonise approaches, for example through EU Network Codes. However, others do not. For example, given that most Nordic countries as well as Germany now have, or have made plans for, a strategic reserve, this is an important area to start discussions.

3. Evolve price areas as conditions change

Nord Pool already goes further than most European markets to specify geographically specific electricity prices. The current price areas are based on administrative delineations. In principle, these areas should have some flexibility over time, as differences in the supply/demand balance and congestion in the transmission network change. Such changes have long lead times, as they require a range of adaptations by market participants.

A more far-reaching future reform would be to adopt the principle of *nodal marginal pricing*[42], which is widely used in the U.S. However, this would be a major departure, requiring a centralisation of the operation of the market. It would affect the current mechanisms for financial trading and contracts as well as competition for retail customers. The benefits would be substantial only if there were significant network congestion.

3.3 Options for a market-wide capacity mechanism

Many of the above reforms would be ambitious, and some could require significant lead time to implement. They nonetheless all represents a further development rather than a replacement of the key elements of the current market. If it were decided that they would not suffice, a further step could be to combine reforms with the introduction of a capacity mechanisms. This would create a new market, for capacity as opposed to energy. In doing so, it would deeply affect the functioning of the energy market, as we discuss below.

There are a number of different varieties of capacity mechanism (cf. Figure 3.4). They all have in common the objective to ensure that there is enough capacity in the power system to cover demand at all times.

[42] Nodal pricing, or locational marginal pricing, is a method of determining prices whereby market-clearing prices are calculated for physical locations on the transmission grid, ‘nodes’, where energy is injected by generators or withdrawn for consumption.

Figure 3.4 There are five main categories of capacity mechanism

		Capacity mechanism	Type of mechanism: Targeted	Type of mechanism: Market-wide	Examples of countries where used
Volume-based	Financial	**1 Reliability option**	☐	☑	•Italy (2018-) •Ireland (2017-)
Volume-based	Financial	**2 Capacity obligation**	☐	☑	•France (2016-17)
Volume-based	Physical	**3 Capacity auction**	☐	☑	•UK
Volume-based	Physical	**4 Strategic reserve**	☑	☐	•Denmark •Sweden •Finland •Germany
Price-based	Physical	**5 Capacity payment**	☑	☑	•Ireland •Spain

Note: List of countries is not exhaustive.

Source: Copenhagen Economics based on ACER (2013) and European Commission (2016).[43]

The need for different capacity mechanisms arises in part because the problem of capacity shortage also can differ. There may be problems of a lack of baseload generating capacity, but the problems may also be limited to times of peak demand. Different kinds of capacity mechanisms address different problems (see Figure 3.5).

[43] ACER, 'Pursuant To Article 11 Of Regulation (EC) No 713/2009, The Agency For The Cooperation Of Energy Regulators Reports On: Capacity Remuneration Mechanisms And The Internal Market For Electricity'; European Commission, 'Commission Staff Working Document. Accompanying the Document Report from the Commission Interim Report of the Sector Inquiry on Capacity Mechanisms'.

Figure 3.5 The choice of capacity mechanism depends on market settings and objectives

Capacity mechanism	Objective	Advantages and disadvantages
Strategic reserve The transmissions system operator (TSO; *Svenska kraftnät* in Sweden) procures capacity to be deployed in periods of scarcity. The procurement is often done through auction. The strategic reserve is activated only when other bids fail to clear the market. No explicit reliability standard needs to be specified, but the volume of the reserve must be decided.	• Ensure short-term security of supply by keeping some generation available in times of scarcity. • 'Top up' the capacity in addition to what the market is expected to provide.	+Limited in scope and administrative burden. - Does not address underlying structural issues or regulatory failures. - May interfere with investment decisions that would contribute to security of supply. - If activation is triggered by a threshold price, this effectively acts as a price cap in wholesale markets, undermining scarcity pricing.
Capacity payment The TSO pays a certain sum of money per unit of capacity available during peak load times. Similar to feed-in-tariffs.	• Ensure long term security of supply by providing reliable investment signals to owners of generating capacity. • Address market-wide and general problems that are not restricted to certain locations or generation types.	+Contributes to long-term security of supply. - Costly if all available capacity is remunerated. - Could prop up unprofitable capacity at high cost to consumers. - Does not address price volatility
Capacity auction / central buyer mechanism An external party (e.g., the TSO) determines the amount of capacity to be available during times of peak load. Producers (and sometimes large consumers) bid in an auction to make capacity available. The marginal bid sets the price, which is paid to all winning bidders.	• Address general shortage of capacity directly by procuring the amount of capacity needed.	+Can effectively resolve problem of short-term capacity shortage. - Risk of over-procurement due to heavy reliance on central decision-making to determine required capacity. - Difficult to ensure participation by all resources that could contribute to improve reliability, notably interconnectors and demand resources.
Reliability options Retailers are required to buy ROs to meet their demand at time of scarcity. Sellers, i.e. generation owners, commit their available capacity at times of scarcity and forego revenue from price spikes in return for a stable revenue stream.	• Directly addresses the problem of 'missing money' for investments by allowing scarcity pricing (as revenue streams), while at the same time insulating consumers from price peaks.	+Provides price signals required for investment while avoiding controversial price volatility. - May not guarantee security of supply, only provides economic incentives to sell capacity at reference price.
Capacity obligation Large consumers and electricity retailers are requires to ensure a margin between available capacity and delivered power. The obligation can be met through bilateral contracts that allow the holder of the contract to dispose of capacity. The contracts be tradable certificates sold by generation owners (or storage and demand reduction). If the promised capacity is not available, a penalty fee must be paid.	• Solves a general shortage of capacity with limited administrative intervention.	+The amount of capacity need not be determined centrally; instead, price signals provide the necessary incentives. - Does not guarantee short-term security of supply, only provides an economic disincentive for failing to keep capacity available. - Depending on the level of the penalty fee and other administrative parameters, capacity may still be over- or under-procured. - May create barriers to entry of new generation, leaving room for existing capacity providers to exercise market power to the detriment of consumers.

Depending on which capacity providers receive payments, mechanisms can either be *market-wide* or *targeted*. With targeted mechanisms, support is only provided to the additional capacity required to meet certain reliability criteria. The Swedish strategic reserve is an example of such an arrangement. Targeted mechanisms generally do not address long-term, structural problems that prevent investments in capacity from taking place. The European Commission therefore sees such schemes as temporary measures to be used while the underlying causes of capacity shortages are being worked out, e.g. through broader power market reform.[44]

In market-wide mechanisms, all providers of capacity receive payments. In addition to power plants, this may also include other capacity resources such as storage (e.g. batteries, electric vehicles) and voluntary demand reduction. In practice, a market-wide capacity means establishing 'capacity' as a product separate from 'electricity' in the power market.[45] These mechanisms are thereby better equipped to alleviate problems of systemic capacity shortages by providing all generating capacity with remuneration, including new entrants.

SEVERAL OPTIONS EXIST FOR INTRODUCING MARKET-WIDE CAPACITY MECHANISMS

There are several alternative design options available for market-wide capacity mechanisms.

4. **Price-based vs. volume-based mechanisms.** In volume-based mechanisms, an external party, often the TSO, determines the amount of capacity required (the adequacy requirement), while the price of capacity is set by a competitive market.

   In price-based mechanism, the external party instead determines the price it pays for a given capacity product through capacity payments. These payments can be available to all providers of capacity (i.e., market-wide mechanisms) or only to certain types of capacity (i.e., targeted mechanisms).

5. **Physical vs. financial mechanisms.**[46] Under physical mechanisms, the TSO directly procures capacity, often through auction, in order to ensure that an adequacy requirement is fulfilled.

   By contrast, under financial capacity mechanisms, the amount of capacity required is not directly specified, but instead indirectly determined through the penalty applied for failing to provide capacity as mandated by the TSO. Compliance may be demonstrated by surrendering certificates from operators of generation facilities,

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44 European Commission, 'Commission Staff Working Document. Accompanying the Document Report from the Commission Interim Report of the Sector Inquiry on Capacity Mechanisms'.

45 Ibid.

46 Capacity mechanisms may also be classified as centralised (physical) or de-centralised (financial), which overlaps with the distinction between physical and financial mechanisms. The definition of these depends on who decides on the volume of capacity the system requires. Under centralised capacity mechanisms, the amount of capacity procured is determined by a central buyer (the TSO). Under decentralised mechanisms, the amount is determined by the penalty set on non-compliance of capacity obligations and reliability options.

which is the case with *capacity obligations*: Users are required to own certificates equal to their peak capacity requirements. Certificates are issued to generators and possibly other capacity providers based on their ability to provide capacity. A penalty system ensures sufficient incentives for the user side to own certificates.[47] These mechanisms require little regulatory intervention, and therefore can also be less exposed to regulatory risk.[48]

INTRODUCING A CAPACITY MECHANISM IS A COMPLEX UNDERTAKING THAT REQUIRES SIGNIFICANT LEAD TIME

Regardless of the design choice, a market-wide capacity mechanism is likely to constitute a major and likely irreversible step for Swedish power market. Market-wide capacity mechanisms incentivise investments in long-lived capital stock, and it may prove politically impossible to remove this support. On they are in place, capacity markets may also lead to lock-in effects through a feedback loop: introducing the capacity market leads to lower prices in wholesale markets, which in turn gives rise to need for capacity payments.

Introducing a capacity mechanism cannot be a solution to fixing short-term problems. Designing a successful capacity mechanism is a complex undertaking. It requires a number of design choices to ensure that objectives are met, and to safeguard cost-effectiveness (see Box 3.5). These design choices can help reduce the distortionary effects of capacity mechanisms, e.g. by ensuring technological neutrality and fair competition between all capacity providers. This requires putting in place a suitable product definition (*what* should capacity providers deliver and when?) and setting up eligibility criteria (*who* is allowed to deliver it). The capacity product definition is at the heart of capacity market design. It can be technology-neutral in principle, but in practice often it is not. Dispatchable generating capacity, i.e. producers that can ramp production up and down, often is favoured as its capacity is easier to define. This may be hydropower (as in Portugal), but is often fossil fuel-fired plants. In France and Belgium, only gas-fired plants are eligible for capacity payments. In Spain, there is a specific mechanism to provide capacity payments specifically to coal plants.

These choices also affect competition between existing plants and potential entrants on the market. New entry is harder when the capacity products are strictly defined by regulators and costs and risks of developing new products are harder to bear. This can stifle innovation. These questions are all the more important as a capacity remuneration schemes depress the prices for energy (as some of the cost of capacity is paid for through other means), and thus the prospects for any production that is not included in the mechanism.

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[47] Because the price of provided capacity is not determined through a central bidding process, but by market participants, financial capacity mechanisms are also called 'de-central obligations', e.g. in the European Commission's nomenclature.

[48] Federal Ministry for Economic Affairs and Energy (BMWi), 'An Electricity Market for Germany's Energy Transition Discussion Paper'.

Box 3.5 Design of a capacity mechanism requires detailed choices across a number of different parameters

1. Reliability standards and level of capacity

A central planner must answer the question: how much capacity is required? This is in turn based on the level of reliability required. Reliability standards must be defined administratively as there are no mechanisms for end-users to collectively express its preference for reliability – although smart grid technologies could change this in the future.

2. Capacity product definition

The product determines what capacity providers need to deliver so that the adequacy requirement is met, thereby entitling providers to remuneration (the obligation), and what happens if they fail to meet this obligation (the penalty). In Sweden, the obligation is to deliver electricity or reduce demand when instructed by *Svenska kraftnät* during the period 16 November to 15 March each winter.

Defining the capacity product also means defining which providers of capacity are to be included in the mechanism. Should all types of generators be included? Should both demand- and supply-side resources be included? Should interconnectors and generators in other countries be included? It also is a standard recommendation to ensure regional coordination; in reality, however, most capacity mechanisms are domestic policies.

3. Lead-time and contract duration

Lead time: the time between entering into a capacity contract and the obligation to make capacity available. The UK has four-year contracts, assumed to be the time required to build a new gas turbine, but also one-year contracts intended to enable the use of more accurate demand forecasts when determining the amount of capacity to procure. For existing generation and demand response, shorter lead times may be more appropriate.

Contract duration: commonly three years, although some mechanisms have used longer durations.

4. Method for price discovery

In volume-based mechanisms, where the TSO specifies the amount of capacity needed, a competitive method of setting prices is a key issue. This is important to minimise costs of the scheme; to send long-term signals for market entry and exit by revealing the real value of capacity; and to avoid generators exercising market power. In the European Commission's recent sector inquiry, all systems surveyed include some method of competitive price-discovery, rather than administrative allocation processes.[49] Globally, many countries have reformed their systems to include an auction mechanism. If there is a central procurement procedure, as with a strategic reserve, the administrator determines which costs should be factored into the bidding process.

Source: Copenhagen Economics based on European Commission; Bergman; Eurelectrics; IEA; Battle et al.[50]

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49 European Commission, 'Commission Staff Working Document. Accompanying the Document Report from the Commission Interim Report of the Sector Inquiry on Capacity Mechanisms'.

50 Ibid.; Bergman, 'Mot En Integrerad Europeisk Marknad För El'; Eurelectric, 'Capacity Mechanisms in the New Market Design. EURELECTRIC's Views'; IEA, 'Repowering Markets'; Batlle, et al., 'The System Adequacy Problem Lessons Learned from the American Continent'.

50 Bergman, 'Mot En Integrerad Europeisk Marknad För El'.

In theory, and in practice in some cases, all resources contributing capacity could be eligible to receive remuneration, including electrical storage, transmission lines to neighbouring regions, and demand response. The capacity product need not necessarily be physical energy, but any resource that is available to contribute to reliability – such as demand reduction, energy efficiency, or transmission investments. Accounting for interconnectors between countries or regions is a particular challenge. These do provide capacity services, but cannot be reserved in an internal market. If demand response is not included in the capacity mechanism, the incentives to invest in demand side measures that deliver reliability, such as energy efficiency measures, may be reduced, especially as the capacity mechanism results in lower prices.[51]

In addition to the time it takes to design a capacity mechanism, if the mechanism is geared toward supporting capacity that has not yet been built, there may also be significant lead time before capacity that has been procured can enter the market. The capacity mechanisms in the UK and France took between 3 and 5 years between decision and implementation, after which there was an additional 3-4 years of lead time before the procured capacity could be delivered.[52]

Another consideration is that capacity mechanisms often need to be revised. The PJM (Pennsylvania-New Jersey-Maryland Interconnection) market in the USA is a case in point. The market has undergone a number of revisions to eliminate opportunities for strategic bidding, reduce the volatility of prices, and ensure capacity is built when and where it is required. Repeated tweaks have required extensive and ever more complex rules. Each change also has been contested, as changes to an existing scheme inevitably create winners and losers; the last proposed revision in 2015 drew heavy fire. Issues that continue to be debated across US capacity markets include the penalties for non-compliance, the extent of capacity market zones, and the shape of the demand curve used to match bids for capacity to a procured volume.[53] The same tendency also can be seen in the recently introduced British capacity mechanism, which already has seen changes to rules guiding qualification for long-term contracts, modifications to the treatment of interconnectors, and proposals to change the rules for participation of demand-side response.[54] While some of these changes are no more than valuable learning, they also are an indication of the complexity of capacity mechanisms.

Finally, there is a need to consider implications for trade in electricity. As noted, capacity mechanisms typically are domestic policies. However, as electricity markets move towards closer integration and harmonisation, it would also be desirable to cooperate across borders in order to share capacity resources and reduce cost. In addition, differing mechanisms across markets can affect trade – an experience illustrated by the effect on trade between Finland and Russia observed as the latter introduced a capacity market that depressed wholesale prices. Capacity mechanisms therefore can become a matter of competition policy and raise questions about EU State Aid rules. In a Nordic context, where wholesale power markets are closely integrated though Nord Pool, a joint Nordic capacity mechanism would be preferable to separate domestic ones.

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51 Bergman, 'Mot En Integrerad Europeisk Marknad För El'. Ibid.
52 Energinet.dk, 'Teknisk Baggrundsrapport - Markedsmodel 2.0.pdf'.
53 Spees, Newell, and Pfeifenberger, 'Capacity Markets - Lessons Learned from the First Decade'.
54 NERA, 'The British Capacity Market: Reflections on a Visible Hand'.

Chapter 4
Evaluating the options

In this chapter, we evaluate how different choices of market design contribute to the objectives of reliability and security of supply, cost-effectiveness and competitiveness, and environmental objectives. Overall, we conclude that retaining and further developing an energy-only market has important advantages over the introduction of a capacity remuneration mechanism (CRM). The costs of energy supply are likely to be lower, including through greater potential for innovation, and there is no intrinsic conflict with environmental objectives. Meanwhile, the introduction of a CRM has disadvantages: it carries risk of costly over-investment, is sensitive to design error, and is likely irreversible even as current reliability concerns could be transient.

All of this hinges on ensuring that an energy-only market can operate freely to attract investment in the capacity needed. If this cannot be achieved, and if market signals are too distorted by other regulatory intervention, it may not be possible to safeguard reliability without regulating it through a CRM.

4.1 Reliability and investment

Reliability can be broadly defined as the ability of an electricity system to provide the amount of electricity consumer's desire (and wish to pay for) within accepted standards. It depends on multiple factors, from the installed infrastructure in networks to generation, to demand side-participation, and decisions taken in the operation of the system (Box 4.1).

As a starting point, it is clear that capacity markets can provide high reliability, but equally that this comes at a price. An electricity system where the total amount of capacity is decided administratively can achieve arbitrarily high reliability. However, capacity has a cost, and too much capacity saddles consumers with higher prices. This dilemma was at the heart of the original motivation for liberalisation: regulated markets where investments were administratively determined tended to over-invest in capacity, resulting in higher costs for consumers. CRMs often are prone to the same problem (see below). The important question therefore is whether the additional reliability is worth the additional cost. The starting point for this must be to consider whether the current market design can achieve 'enough' reliability.

Box 4.1 Reliability requires security, firmness, and adequacy

- **Security** is a short-term issue, and refers to the ability of the system to respond to rapid fluctuations in available supply and demand and withstand sudden disturbances, such as electric short circuits or unanticipated losses of system components. It is the responsibility of the transmission system operator and depends to a large extent on operating reserves.
- **Firmness** is a short- to medium-term issue, and refers to the ability to mobilise already existing capacity effectively. Relevant issues include maintenance schedules, reservoir management, start-up schedules, etc.
- **Adequacy** is the existence of enough available capacity and sufficient demand side flexibility to ensure system balance. This is a long-term issue, dependent primarily on whether investors find the remuneration available high enough, and risk low enough, to bring forward the investments required; and whether the right incentives are in place to develop flexibility in the longer term.

- Adequacy in turn has three aspects
  - Peak capacity: that there is sufficient capacity to handle peak load situations, accounting for any demand response
  - Flexibility: that available resources can adjust output and consumption over the time spans required to handle variations in load and balance the system
  - Back-up capacity: that capacity is available to serve demand also during prolonged periods of low output from variable generation (wind and solar)

Source: Copenhagen Economics based on Pérez-Arriaga and ENTSO-E.[55]

NEAR-TERM RELIABILITY PROBLEMS ARE NOT DUE TO A FLAWED MARKET DESIGN

The most immediate potential reliability problem in the Swedish power system is the prospect of simultaneous and large-scale exit of nuclear power plants. This would abruptly change not just the capacity situation (adequacy), but also other important system services, such as inertia (security). We know of no assessment that has fully investigated the implications of such a scenario, but it can be taken as given that a rapid exit would raise reliability concerns.

This has raised the question whether there is a problem with the underlying market design. If the market design results in decisions that are 'undesirable' from the point of view of reliability, perhaps it needs to be reformed? However, this line of reasoning risks two major confusions:

First, the key issue is not the withdrawal of capacity *per se*, but the fact that it risks being abrupt, simultaneous, and large-scale. The current market design is equipped to handle the withdrawal of capacity when this originates in market processes (e.g., reduced profitability of existing plant vs. new ones) and when there is sufficient lead time to allow

[55] ENTSO-E, 'ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2015'; Pérez-Arriaga, 'Generation Capacity Adequacy: What Economic Rationale for Support Mechanisms?'

the system to adapt in stages, prices to rise as capacity decreases, and market participants to form expectations and undertake the investments required. However, it is beyond any decentralised market process to handle the prospect of simultaneous and centralised withdrawal of very large amounts of capacity.

Second, the reason that investments to prevent such exit might not be viable is primarily that prices for *generation* are low, not that there is an underlying lack of a mechanism to pay for *capacity*. Specifically, policy to build new renewables capacity is producing structural over-capacity across the region. This combines with other factors to produce a situation of low prices. These factors in turn interact with the new regulatory requirements for new investment to continue operation. The ordinary mechanisms for timing the exit of capacity thus are not in play.

To investigate these issues, we model different scenarios for the electricity market in 2025. The results show that continued low prices are a possibility. A decisive factor is whether there is continued expansion of wind power at a rate significantly higher than the growth in demand, especially if combined with low commodity prices. Such a scenario could result in depressed prices that are indeed too low to pay back re-investments. However, in a different scenario with more limited wind expansion (more in line with demand growth) and medium commodity prices, prices would recover where investment could very well proceed. Of course, to an investor a number of other factors matter – from the degree of risk of different scenarios, to the precise path of prices. However, the model analysis suggests that long-term policy choices about whether to subsidise further new entry (beyond the growth in demand) become a key factor behind the prospect of a reliability crunch.

This leaves broadly three options for how to handle the need for near-term investment

- The first is to clear the near-term investment hurdle through 'out of market' intervention. Examples could be the reduction of the nuclear capacity tax, or (if this does not suffice) some other form of intervention such as guarantees, mandates, or payments.
- The second would be to change the market design. In principle, future payments could be provided through a capacity mechanism. However, this would turn the logic of capacity mechanisms on its head: instead of using it to address a problem of *under*-capacity, it would seek to enable continued *over*-capacity. In effect, the capacity payments would be akin to counteracting the effect of subsidies for one type of generation by introducing subsidies for another.
- The third would be to address the underlying issue causing low prices, and keep the current market design. This would likely require that targets for renewable electricity are set so that growth does not exceed the underlying market demand for new generation capacity across the region as a whole.

Option 1 would be the least disruptive, if it is feasible. Option 2 risks creating a significantly less efficient market design. Option 3 would in many ways create a better foundation for the future – both for reliability, and for other objectives. However, it is not a *sine qua non* for future reliability, provided future withdrawals of capacity are gradual rather than occuring all at once.

IN THE MEDIUM TERM, THE SWEDISH ELECTRICITY SYSTEM NEED NOT FACE A RELIABILITY PROBLEM UNDER AN ENERGY-ONLY MARKET

Assuming that investments go ahead to an extent where a reliability crunch is avoided, the longer-term question is whether a continued energy-only arrangement can achieve sufficient reliability in plausible future scenarios for how the electricity system develops.

Two misunderstandings often influence discussions about this issue:

- The first is that energy-only markets risk failure to deliver enough reliability because there is nobody 'responsible' for planning or coordinating the investment decisions. In fact, electricity markets work just like other markets in this regard. The 'responsible' party are those investors who stand to make money from entering the market. The coordinating mechanism is the market price.
- The second misunderstanding is that there is 'no payment for capacity' in an energy-only market. As described above, the mechanisms are clearly established, through infra-marginal rents and scarcity pricing.

Targeted reforms can increase reliability under an energy-only approach

The question is instead whether there are reasons to think that these mechanisms are inadequate. Recapping the previous discussion, there are broadly eight reasons why energy-only markets might not suffice for reliability (adequacy and security):

1. **Strict reliability standards** can exceed the level that markets achieve – i.e., even if markets achieve the reliability that consumers are in fact prepared to pay for, politicians might want a higher level, which then has to be paid for separately
2. **Political uncertainty can undermine investment**, with particularly strong impact on investors in already riskier peaking capacity
3. **Suppressed prices** can depress earnings from energy production to the point where plants that also provide essential services do not earn the revenues required to cover costs and stay in business
4. **Price caps** (explicit or threatened) can undermine scarcity pricing required for peak capacity
5. **Incomplete or missing ancillary service markets** risk inadequate payment for important system services
6. **Out-of-market actions** by TSOs (including operation of the strategic reserve) have the effect of undermining prices that would support commercial resources
7. **Missing forward markets for electricity** and hedging products can hold back investment in capacity required for system reliability
8. **An inactive demand side** can contribute to higher capacity requirements than markets can easily pay for

If there are concerns that the current energy-only market does not provide sufficient reliability, the first step should be to address these factors. This requires a combination of political commitment, improved market design, or long-term innovation:

- **Political commitment** to the market mechanism may be the single most important lever for achieving greater reliability under an energy-only market. It can alleviate all of points 1-4 above. *Reliability standards* can be defined, if possible based on economic principles that also guide other aspects of market design (e.g., through by a consistent use of VOLL). *Political uncertainty* depends directly on the political process. *Inefficiently low prices* arise primarily because investment has been forced through political decision, and unlinked from underlying supply and demand in the market. *Scarcity pricing* will become ever more important with greater shares of wind power, and its feasibility increases with pre-commitment to the future price spikes that are required to bring forward new capacity that will be required.

- **Improved market design** can address 4-6. *Price caps* can be raised to levels closer to VOLL, especially if accompanied by improved market oversight. *Missing ancillary service markets* can be defined, following the Irish and other examples. *Out of market actions* by the TSO can be limited, with a first step to ensure that the strategic reserve does becomes less distorting.
- **Long-term innovation** can alleviate other challenges, including 7-8. In particular, technological development and new business models already are starting to show the way to a more *active demand side*.

Not all of these initiatives would be feasible for Sweden to address on its own. Issues such as price caps require coordination at least at the Nordic level; others depend on EU-wide network codes, while political uncertainty depends on EU policy, including the EU ETS. Nonetheless, Sweden could play a part in initiating the long-term processes required for reform, and also make changes where it has jurisdiction to do so.

The weight of experience suggests that it would be premature to abandon the current energy-only arrangement

Will some combination of the above suffice to give longer-term reliability? It is not possible to give a definitive answer. However, in our view the weight of evidence suggest that there is substantial reason to think that an energy-only market can continue to achieve sufficient reliability:

First, the Swedish situation differs materially from that in many other countries now introducing capacity mechanisms. For example, the French market has seen prices hit price caps for many years.[56] The choice therefore was to commit to and improve scarcity pricing, or to introduce a capacity mechanism, with the latter option chosen. By contrast, Nord Pool has rarely seen price spikes of this type. Sweden has an opportunity to prepare markets ahead of time to avoid similar tensions.

An even clearer contrast is the Great Britain electricity market in the UK, where the introduction of a capacity mechanism took place against a perfect storm of factors (see Box 4.2). Sweden need not face anything like the same cocktail of acute reliability problems, investment requirements, or politically induced uncertainty (always provided remaining six nuclear reactors are not abruptly withdrawn from the market).

56 Newbery, 'Missing Money and Missing Markets'.

Box 4.2 The UK Energy Market Reform entailed significant re-regulation of investment to improve security of supply

A driving factor behind recent energy market reforms in the United Kingdom was new regulatory requirements for pollution controls on its coal plants. Investment decisions hung in the balance for many years, but in the end operators decided not to invest. This combined with other factors to create a situation of very low capacity margins only a few years in the future. The government estimated that the UK energy system needed new investment on the order of 100 billion pounds.

The risk of lower margins in turn occurred alongside significant investment challenges for all other types of capacity: planning law and ineffective support systems for renewable electricity; high and volatile fuel natural gas prices; and long lead times and uncertain costs for nuclear power – all compounded by significant uncertainty induced by a highly unstable energy policy regime.

Investors thus concluded that politicians could not be trusted to lay down stable parameters within which they could take the risk of committing to enter the market; and politicians concluded in turn that, in such a situation, the market could not be trusted to provide sufficient security of supply.

In answer to this conundrum, an *Energy Market Reform* package introduced a range of measures to reduce risk and bring forward investment. The government now decides the quantities of different types of investment, through direct procurement of nuclear power; auctions for renewable electricity; and capacity markets for thermal capacity. The remaining energy market serves mainly to operate already existing plants, and to set a reference price for electricity. In effect, investment decisions have been re-regulated.

Sources: Copenhagen Economics and Newbery[57]

Second, there is evidence that energy-only markets can underpin investment in the right circumstances. Since liberalisation, the Swedish market has both closed costly capacity, and subsequently attracted investment in the extension or maintenance of nuclear capacity, and the expansion of hydro capacity as well as combined heat and power. Texas's ERCOT market provides a recent example where a lively recent debate took place about abandoning energy-only markets in favour of capacity mechanisms. The debate was prompted by shrinking generation margins, which prompted a number of assessments suggesting that a capacity mechanism would be necessary.[58] However, the outcome in fact shows the opposite: increased commitment to scarcity pricing through higher price caps and a scarcity adder produced the new investment required to restore reliability. In combination with lower demand growth, this has restored capacity margins to the point where all plans for capacity mechanisms have been shelved (Box 4.3).

57 Newbery, 'Reforming Competitive Electricity Markets to Meet Environmental Targets'.
58 Center for Energy Economics BEG- UT, 'A Primer on the Resource Adequacy Debate in Texas'; Newell et al., 'ERCOT Investment Incentives and Resource Adequacy'.

Box 4.3 The Texas electricity market has staved off reliability risk through increased commitment to scarcity pricing

Texas is unusual in the United States as an energy-only market. Historically the reserve margins had been high, ranging between 13-19%. However, rapid electricity demand growth has gradually eroded this, and by 2011 the margin remaining at peak load had shrunk to 7%. This is significantly below the almost 14% thought to be required to meet a "1-in-10" reliability objective (i.e., no more than one load-shedding event in every decade).

To some, this situation seemed to confirm the view that energy-only markets risk not creating the required investment incentives for peak capacity in situations of low wholesale prices. A number of voices therefore proposed the introduction of a capacity remuneration mechanism, similar to those prevalent in most other major U.S. electricity markets.

The regulating body (ERCOT) took the step of reinforcing the mechanisms for scarcity pricing. This had been at 3,000 USD/MWh (less than the current 3,000 EUR/MWh in Nord Pool) until 2012, but has since been progressively increased to reach 9,000 USD/MWh in 2015. A key motivation for the increase was that average wholesale prices were lower, owing to lower natural gas prices and an increased share of wind generation. In parallel, ERCOT introduced an 'operating reserve demand curve', that increases prices when operating reserves fall below 4,000 MW of capacity, in a version of the scarcity adder discussed in Chapter 3.

Two developments helped swing the debate away from introducing a capacity market. First, demand forecasts were revised down, reducing fears of future capacity problems. Second, in the course of 2015 an additional 9,000 MW of investment in new gas-fired capacity was announced, taking the overall system from a decline of reserve margins to a significant increase to 20%.

In this case, reforms to the market and commitment to the approach of scarcity prices therefore appear to have sufficed.

Sources: Maize 2014; S. A. Newell et al. 2014; Ercot 2015[59]

The future need for a capacity mechanism depends in large part on whether prices reflect the cost of supplying electricity

There may be a need to reassess these issues at a later point, and especially with a higher share of wind power. As noted, this need not raise qualitatively new issues, but it places greater requirements both on mechanism to pay for peak capacity (scarcity pricing), flexibility (intraday and balancing markets), and system services (ancillary service markets). In a scenario with insufficient political acceptance or initiative to provide the necessary price signals, a capacity mechanism may need to be considered. However, it equally is possible that increased demand response and the development of energy storage takes the edge of problems before any such need arises.

[59] Maize, 'Texas and the Capacity Market Debate'; Newell et al., *Estimating the Economically Optimal Reserve Margin in ERCOT*; Ercot, 'Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2016-2025'.

For the time being, however, absent any pressing reason to act otherwise, the least disruptive approach would be to start a process of targeted market reforms, while retaining the strategic reserve as intended until 2025.

4.2 Cost and competitiveness

Most assessments conclude that the liberalisation of the Swedish electricity market has resulted in a lower-cost electricity system, with lower costs to consumers as one of the resulting benefits, although it can difficult to make strong conclusions about a counterfactual scenario with continued regulation.[60] The main mechanism behind these benefits has been more efficient investment and exit decisions. To a very large extent, the cost of the future electricity system similarly will depend on the ability to ensure efficient investments.

RENEWABLE ENERGY TARGETS FORCE AN ACCELERATED TURNOVER OF GENERATION CAPACITY, RESULTING IN HIGHER COSTS

The single most important determinant of the cost of the future Swedish electricity system is likely to be the rate of turnover of generation plants.

A common confusion is that renewable energy targets are costly primarily because the relevant technologies are more expensive than other options. This has often been the case in the past, and still applies in some EU countries, but in Sweden's case, wind power at *c.* 60-70 EUR/MWh is in fact cheaper than most other potential options for new capacity.[61] The main reason that such targets can be costly (and subsidies thus required) is instead that no or little new capacity is required to meet demand. New wind power therefore has to compete not with other new entrants (as would be the case if investment were market driven rather than mandated), but with electricity from existing plants. Existing plants almost invariably are cheaper; for example, existing nuclear plants can produce electricity at a cost of 25-35 EUR/MWh. The cost therefore is one of accelerating the turnover of the generation mix.

As noted, for many EU countries with a high-carbon electricity mix, accelerating the turnover of the electricity generating fleet may be an unavoidable cost of meeting climate targets. In Sweden's case, however, climate targets create no such necessity. Whether it is worth incurring the additional cost therefore must be a political judgement based largely on other preferences about the generation mix (notably, preferences regarding renewable energy sources and nuclear power).

The costs resulting from accelerated turnover of generation are largely unrelated to market design choices

60 E.g., Lundgren, 'Consumer Welfare in The Deregulated Swedish Electricity Market'; Brännlund, Karimu, and Söderholm, 'Elmarknaden Och Elprisets Utveckling Före Och Efter Avregleringen: Ekonometriska Analyser'.
61 Elforsk, 'El Från Nya Och Framtida Anläggningar 2014'; Sweco, 'Ekonomiska Förutsättningar För Skilda Kraftslag'.

The current lack of a business case for new capacity (renewable or otherwise) does not arise because the current market design is rigged either against new investment in general, or against renewable electricity in particular. A market can only support investment in new capacity if there is an underlying need: because existing capacity cannot serve demand; there are opportunities to export to markets with higher prices; there is a need to provide electricity during periods with scarcity (and prices higher than average); or new capacity can outcompete existing capacity through lower cost. None of these currently apply. The fact that the market does not underpin new investment therefore is not a sign that it is not working and needs to be redesigned – it is in fact working as could be expected.

This also means that there are clear limits to whether a changed market design can ‘correct’ for the effects of new investment in a situation of over-capacity. It ultimately is a matter of arithmetic that continued entry of renewable electricity must be accompanied by reduced production from other sources if opportunities for increased exports are limited. If the cost of new entry is higher than continued operation of existing plant, total costs will increase. Market design cannot change this.

SUBSIDIES BENEFIT CONSUMERS IN THE SHORT-TERM, BUT LEAD TO HIGHER COSTS IN THE LONG-TERM

The higher costs of increased turnover are unevenly divided. In the short-run, over-capacity has benefited consumers, who pay lower prices. This benefit is to a large extent a transfer from producers, whose earnings from existing plants have been reduced.
In the longer term, however, this mechanism cannot continue to apply. Lower prices are not an indication of a lower-cost electricity system, but result because electricity production is subsidised. As subsidies result in more investment than required to meet demand, the effect is a higher-cost system in the longer run. Even if consumers benefit from lower prices in the short-run, higher costs ultimately have to be paid for. Under current arrangements, consumers also pay for the subsidies. The impact on competitiveness in turn depends on how these subsidy payments are distributed between different consumer groups.

Subsidies also have indirect costs through impacts on consumption and investment decisions

Lower electricity prices also have a number of indirect impacts. We have modelled a scenario where there is continued subsidy of new investment in renewable energy capacity in Sweden, resulting primarily in the expansion of wind power. The scenario also takes account of policies in neighbouring countries, which have similar plans for the continued build-out of renewable electricity. The results suggest that such a scenario could keep electricity prices depressed into the 2020s. Prices would remain significantly below the long-term cost of new electricity supplies; indeed, subsidies to attract new entry of wind power may need to be of a similar size as the price of electricity (or higher, if the cost of capital increases as interest rates recover). On the other hand, this could change in the event of a significant recovery in commodity and CO_2 prices that provided an upward pull on prices in neighbouring countries with more fossil capacity.

Prices below the cost of supplying electricity result in inefficient consumption. Energy efficiency efforts would face an uphill battle. The decision between electricity and other energy sources in a range of consuming sectors would be skewed. Efforts to increase demand response in electricity markets similarly would be stymied. Overall, the subsidy of electricity production risks undermining efforts to achieve a resource-efficient economy.

Similarly, investment, operational, and exit decisions in the electricity sector – other than those related to the build-out of renewables capacity included in support schemes – would be undermined. Examples include investment in increased capacity or flexibility in existing hydro plant, or the efficient trade-off of heat and electricity production in combined heat and power plants.

The size of these costs are difficult to estimate, but they result chiefly from knock-on impacts of setting aside the market mechanism as the organising force for investment decisions.

THE COST OF A CONTINUED STRATEGIC RESERVE CAN BE RELATIVELY MODEST PROVIDED ITS DISTORTING EFFECTS CAN BE LIMITED

As noted in the previous section, it is unclear that the introduction of a capacity mechanism in Sweden is warranted. However, given the significant uncertainties now facing the electricity system, it seems unlikely that the current strategic reserve will be phased out. In recent consultations, nearly all market participants supported its continued operation.

The direct cost of a continued strategic reserve can be relatively modest. The current arrangement has a cost of around 2-3% of the market price for electricity.[62] It ultimately is a political judgement whether this insurance premium is worth paying. Most respondents to recent consultations on the topic suggested that it would be, although this is against a background where depressed prices and uncertainty makes market-driven investment very difficult.

Like other interventions, however, a strategic reserve also has indirect costs resulting from distortions to the operation of energy markets. These are difficult to estimate, and in any case the main impact is likely to be that interfering with scarcity pricing and reliability. The revisions to the design and operation of the reserve as proposed in Chapter 3 would help reduce them.

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62 The cost recently has been around 100 million SEK per year. For comparison, the value of electricity traded at spot prices was 3,400 million SEK.

A CAPACITY MARKET WOULD INCREASE COSTS, BUT BY HOW MUCH DEPENDS ON IMPLEMENTATION RISK

Introducing a more far-reaching CRM would entail larger costs than an energy-only market. The reason is simple: the purpose of a CRM would be to ensure that there is more capacity than would be the outcome under an energy-only arrangement, and the cost of this additional capacity would have to be paid for by consumers. The regulatory decision therefore is whether the additional cost is worth the additional reliability.

The cost of a CRM depends strongly on the success of implementation

Estimating the costs of CRMs often suffers from methodological difficulties. A 'perfectly' working CRM could in theory produce outcomes that do not differ much from those under a 'perfect' energy-only market – except in the direct cost of the additional capacity that the CRM is intended to bring forward. In reality, however, implementation of capacity markets is complex. It involves direct costs of implementation, and risk to market participants both as the market is first introduced and subsequently almost inevitably redesigned. Moreover, setting up a CRM involves the need to specify numerous administrative parameters that often are uncertain and often controversial. The experience to date from PJM and other markets is that markets need to be repeatedly revised. Even then, redesigns are often controversial and contested. Overall, there is a non-negligible chance of 'getting it wrong'.

This dynamic of 'idealised' vs 'realistic' costs is hard at work in impact assessments of CRMs carried out in European countries in recent years. One set of assessments, often arguing in favour of the introduction of a CRM, tends to implicitly assume very smooth implementation. An example of this is the UK Impact Assessment, which indicates small additional costs against large gains to reliability, given the situation in the British market.[63] Other studies with similar assumptions also find relatively modest costs.[64] With assumptions made in these assessments, the cost of a capacity market can be relatively modest.

The picture changes if the methodology allows for the possibility that the system planner is not perfectly informed, but likely to make mistakes. For example, studies for the German government to investigate capacity market options found that the risk of getting various design parameters wrong could significantly inflate costs. In one scenario, the cost increased more than three-fold.[65]

The risk of over-investment is the main source of cost escalation in capacity markets

The key parameter in this regard is the amount of capacity to procure. In most CRMs, the decision of how much capacity to procure is political. It also tends to involve the TSO, which has strong incentives to avoid any capacity shortfall, but much smaller incentives to

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63 GOV.UK, 'Electricity Market Reform – Capacity Market. Impact Assessment (IA)'.
64 E.g., Sweco, 'Capacity Markets in Europe: Impacts on Trade and Investments'.
65 Federal Ministry for Economic Affairs and Energy (BMWi), 'An Electricity Market for Germany's Energy Transition Discussion Paper'; Frontier Economics and Consentec, 'Folgenabschätzung Kapazitätsmechanismen (Impact Assessment)'; r2b, 'Endbericht Leitstudie Strommarkt Arbeitspaket Funktionsfähigkeit EOM & Impact-Analyse Kapazitätsmechanismen'.

limit costs of investment in generation. This creates a risk of upward bias in the amount of capacity. The recent UK capacity auctions provide an example. The design arguably is best-in-class, building on long experience and implementing a carefully thought-out auction. Nonetheless, the amount of capacity procured was very likely excessive, as the TSO and politicians alike had little to lose by procuring large volumes.[66] Another cautionary lesson is that of the South West Interconnected System in Australia. The regulatory agencies governing the capacity market has consistently forecast higher demand than has actually materialised, procuring overcapacity of 900 megawatts (MW) in a system of 4000 MW total capacity, even as new capacity continues to be procured and built.[67] The UK and Western Australian examples thus illustrate different aspects of the well-known problem that arises under regulated markets, in that the parties deciding on investments had little incentive to keep it at cost-effective levels and difficulty making forecasts on behalf of all market participants.

Capacity markets have indirect costs through their impact on energy markets

Over-procuring capacity in turn has a range of knock-on effects. The most immediate is to raise costs for consumers, who pay for it through the capacity charges. More subtly, over-capacity depresses electricity prices. Lower prices might offset part of the capacity payment made by consumers. On the other hand, they affect all decisions that depend on the electricity price. This includes incentives and revenues available to generation that is not included in the CRM. The capacity market in PJM has been through several revisions to attempt to reduce such problems, but leaves some distortions intact.[68]

Several other factors also can affect the cost of a capacity mechanism. One relates to the impact on cross-border trade. With different capacity mechanism arrangements across countries, the efficiencies and greater reliability resulting from trade in electricity can be undermined.[69] Another is the prospect of achieving effective competition in the capacity market, which can be challenging if the number of providers of the specified firm capacity is small. The Swedish market has reduced concerns about market power by integrating Swedish production with that in neighbouring countries. However, a capacity mechanism that extended only nationally could risk higher concentration among participants. A third is that capacity markets can undermine incentives for some types of flexibility, as it is much easier to specific the capacity product attributable to 'firm' production capacity than for capacity with specific flexibility attributes.[70]

Overall, the cost of a capacity mechanism is difficult to assess. Politicians and others who wish to assess whether additional costs are 'worth it' face no easy task. Any future assessment of options for the Swedish market would do well to consider not just the direct costs of an optimally implemented policy, but also a) the costs of suboptimal

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66 Newbery, 'Missing Money and Missing Markets'.

67 Lantau Group, 'Improving Western Australia's Reserve Capacity Market: Steps and Thoughts to Date'; Nelder, 'The Perils of Electricity Capacity Markets'.

68 Bowring, 'Capacity Markets in PJM'; Ciliberti-Ayres and Lawrence, 'Performance Enhancement'.

69 Viljainen et al., 'Cross-Border Electricity Trade between the Nordic Energy-Only Market and the Russian Capacity-Based Market'; DNV GL, 'Potential Interactions between Capacity Mechanisms in France and Germany'.

70 The Regulatory Assistance Project (RAP), 'What Lies "Beyond Capacity Markets"? Delivering Least-Cost Reliability Under the New Resource Paradigm'.

implementation and b) indirect costs through knock-on impacts on trade, competition, and the functioning of energy markets.

4.3 Environmental objectives

The key trade off in evaluating market designs is between cost and competitiveness on the one hand, and reliability on the other. By contrast, either of the options for market design discussed above can accompany the achievement of environmental objectives. Nonetheless, the means for achieving these targets may need to differ depending on which market design is chosen.

In the case of climate targets, liberalised electricity markets (whether energy-only or with a capacity mechanism) are more compatible with a carbon pricing approach than with subsidies and direct political steering of investments. The subsidy approach results in particularly acute tensions between cost and climate objectives in Sweden, given that it risks triggering substantial exit of existing production that is already is low-carbon.

If, on the other hand, objectives include a direct preference for increasing new renewable electricity sources *per se,* then a continued support scheme is necessary – again, not because renewable electricity is more expensive than other new sources, but because there would not be sufficient need for new investment in the first place to ensure continued rapid growth in renewables capacity. However, such a scenario would reach a point where additional existing capacity must withdraw.

Once one set of investment decisions (new build of renewables capacity) has been regulated, several countries also have found it necessary to modify market design to ensure sufficient investment also in other capacity (and especially maintenance or new build of firm capacity). A capacity mechanism is one way to achieve this, but Germany is an example of a country taking a different route, with continued emphasis on an energy-only market supplemented by a strategic reserve.

In sum, there is no incompatibility between an energy-only market and climate objectives – not in general, and especially not in Sweden. However, there is a gradually increasing tension between current market arrangement and attempts to achieve a rapid turnover of the production mix.

AN ENERGY-ONLY MARKET CAN BE COMPATIBLE WITH A HIGH-RENEWABLES ELECTRICITY SYSTEM

Longer-term, it is likely that the Swedish electricity system will be based to a higher degree on renewable electricity, with a more limited role for nuclear power. In particular, Sweden has a large potential resource of wind power at low costs compared to other currently available options for low-carbon electricity. It therefore is relevant to ask whether increasing shares of wind power is compatible with different market designs.

There are some reasons to believe that very high shares would put market arrangements under strain. Increasing shares of wind power would require non-wind generators to earn revenues during shorter time periods with higher prices. Our own modelling of the Nord Pool market for 2025 supports this conclusion. In a scenario with substantially less nuclear and a higher share of wind, episodes with scarcity pricing become significantly more frequent.

With extreme shares of wind, the prices required could go very high: for example, simulations of the Australian NEM electricity market found that prices might need to rise to levels as high as 50,000 EUR/MWh for combined wind and solar power share of around 50%. Given that current markets already struggle to create acceptance for scarcity pricing, reliance on energy-only markets could become increasingly difficult at some point on the road towards very high shares of variable electricity. The researchers behind the study nonetheless conclude that such an arrangement would likely be preferable to using a capacity mechanism.

Such extreme scenarios are in any case far off in the Swedish market. For the shares of variable power likely under the next two decades, it very unlikely that such extreme levels of scarcity pricing will be required. Studies in Germany come to the same conclusion, finding that much more modest peak prices will suffice even with ambitious targets to increase production from wind and solar power.[71]

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71 Federal Ministry for Economic Affairs and Energy (BMWi), ‘An Electricity Market for Germany’s Energy Transition Discussion Paper’.

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Appendix A

Modelling approach and scenarios

Model description

We have simulated the Swedish power market using the Copenhagen Economics Power Market Model, which is a dispatch model of the North European power market. Geographically, the model covers Germany, Denmark, Sweden, Norway and Finland, with all the bidding areas in Sweden and Norway modelled explicitly. One model simulation represents one year, with an hourly time resolution.

The model incorporates two intermittent renewable generation technologies (wind and solar) and five thermal technologies (nuclear, lignite, coal, gas and biomass). In addition, hydropower is represented with both run-of-river and reservoir generation, the latter of which allows available water resources to be used optimally over time, given constraints on water inflow, generation capacity and reservoir capacity.

Main data sources for the model include Svensk Energi, Energinet.dk, Bundesnetzagentur and ENTSO-E for generation capacities, Nord Pool for hourly loads and transmission capacities, and the Danish Energy Agency, the Swedish Energy Agency and Neon Neue Energiökonomik for production cost data.

Scenario description

A number of different factors will in the short to medium term significantly affect the market conditions of the Swedish power market. Important factors are fuel prices, electricity demand, developments in neighbouring markets and EU policies such as the strength of the ETS. We explore some plausible developments in the Swedish power market in order to assess the need for changing the Swedish market design. Our focus is on the next 10 years, with the aim of identifying the decisions during that period, which in turn affect long-term outcomes for the market outcomes and market design. To illustrate this, we construct two scenarios each being a combination of plausible outcomes, but with significantly different market outcomes:

Scenario 1: Return to market based decisions ('market consensus')
Scenario 2: Regulatory intervention and out-of-market decisions

In addition, we simulate a base scenario representing a middle case.

Scenario 1: Return to market based decisions

The principle behind this scenario is a return to a regulation supporting market-based decisions. The main features of the scenario is a strengthened ETS price, and a commitment to link renewable energy growth to electricity market prices. Consequently, if the market signals that no additional investment is required to meet demand and overall climate ambitions, renewable energy growth will be limited. The scenario also includes a rise in fossil fuel prices in turn benefitting especially low-carbon power and infra-marginal plants.

Scenario 2: Regulatory intervention and out-of-market decisions
The principle behind this scenario is that many market outcomes will be driven by decisions basically taken outside the power market. Low fossil fuel prices and ETS prices imply that low-carbon / fossil-free power, is not remunerated much in the market. Consequently, policy makers decide to continue the build-out of wind power – over and above the demand growth – through new renewable energy targets. Moreover, neighbouring countries will continue to expand capacity, especially wind power in Denmark and Germany, worsening the business case for Swedish capacity.

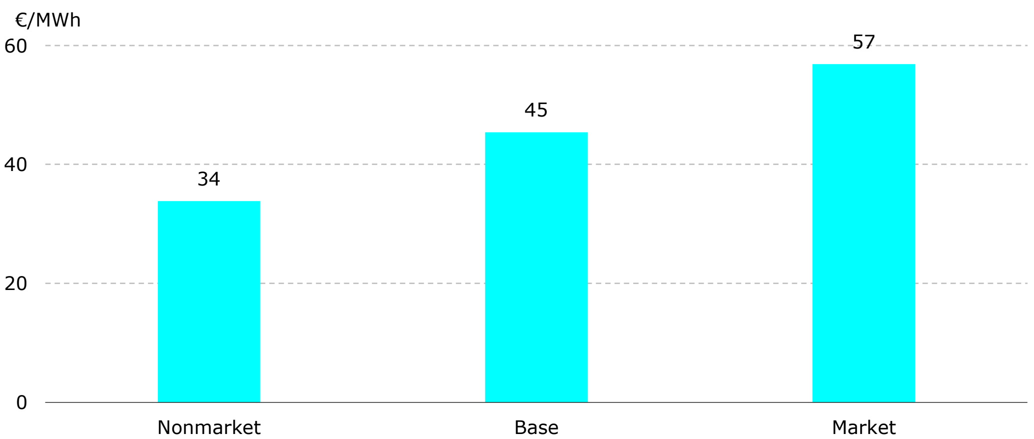
Base case scenario
In addition to the two scenarios we simulate a 'base case' scenario where the situation in 2025 is a step towards market consensus, but not fully there yet. This represents a middle case.

The following section describes which assumptions we have used for a number of important parameters, and how they differ across scenarios. This information is also summarized in Table A.1 below.

Select scenario results

Our model simulations show that in 2025, the average power market prices may differ quite substantially. We estimate the difference between the non-market and the market scenario to be app. €20-25 / MWh, cf. Figure A.1 . The lower price in the non-market is driven by increased deployment of renewable energy and low ETS and fossil fuel prices.

Figure A.1 Average Swedish power market prices, 2025



Note: Simulated for the year 2025

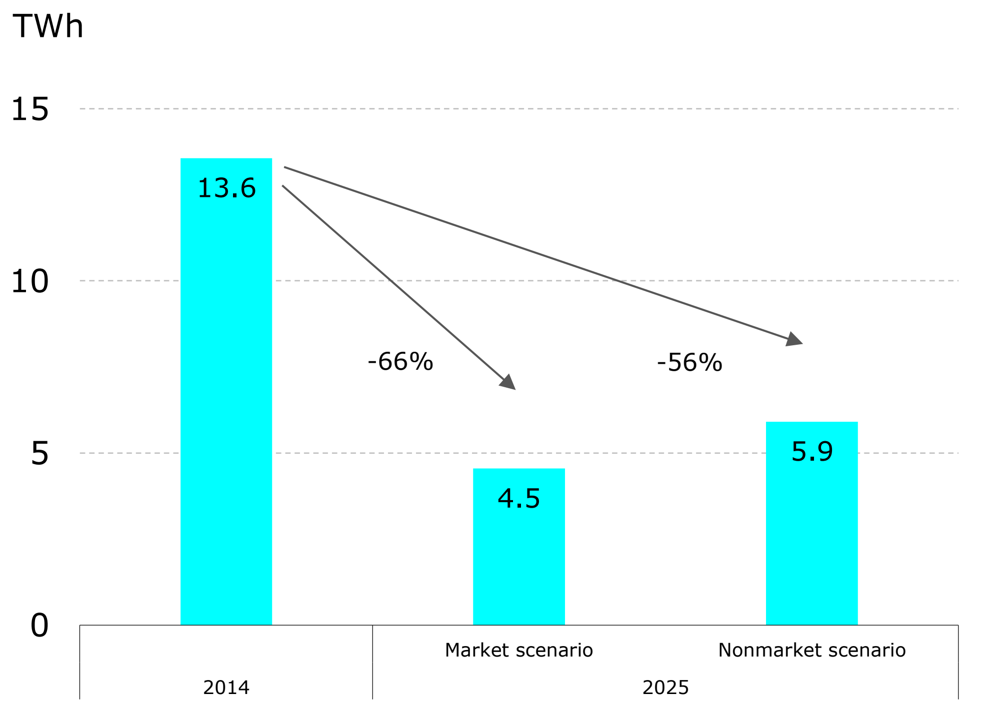
Source: CEPOM simulation

The power price in the base case is similar to what is found by Energimyndigheten[72] suggesting a price of app. €41/MWh, however assuming a lower ETS price and somewhat lower fuel prices.

72 Energimyndigheten (2014), Scenarier över Sveriges energisystem

Going forward, Swedish net exports are expected to decline significantly; we estimate app. a 60 percent reduction, cf. Figure A.2 . One reason is the continued build-up of new capacity in neighbouring countries, which will put further strain on Swedish capacity.

Figure A.2 Net exports from Sweden

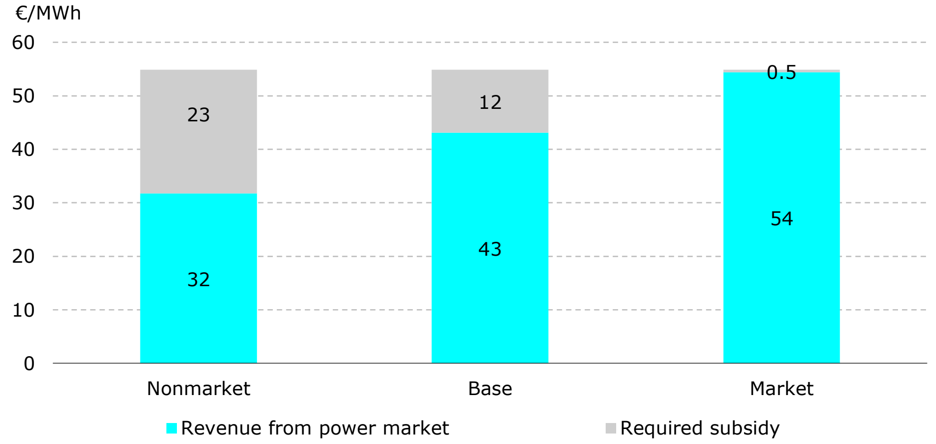


Note: Simulated for the year 2025.

Source: CEPOM simulation

Our simulations show that in the 'return-to-market' scenario, continued deployment of wind energy can be driven almost by the market prices alone, cf. Figure A.3. On the contrary, in the non-market scenario app. two-thirds of required remuneration to wind energy needs to be granted as subsidies.

Figure A.3 Required subsidy to onshore wind energy



Note: Simulated for the year 2025.

Source: CEPOM simulation, cost data from Elforsk's power price calculator

Scenario details

Fuel price assumptions are based on the *Current Policies*, *New Policies* and *450 ppm* scenarios from the World Energy Outlook (IEA, 2015). In our Scenario 1, we assume the highest fossil fuel prices, with price increases in 2025 of 37% for coal and 11% for natural gas, relative to 2015 (constant 2015 prices). The lowest prices for 2025 are assumed in Scenario 2, with nearly the same coal prices as in 2015, and a 9% lower natural gas price. In our base case scenario prices fall somewhere in between. For biofuels we assume an 8% increase, based on Energinet.dk's *analyseforudsætninger*.

ETS prices are assumed to be higher in 2025, relative to today, in all scenarios, with higher fossil fuel prices associated with higher ETS prices. In the base case scenario, we assume 20 €/ton, which is close to the WEO (2015) *New Policies* scenario. In Scenario 1 we assume a higher ETS price, at 30 €/ton, while Scenario 2 sees an ETS price only slightly higher than today's level, at 10 €/ton.

With respect to **renewable energy targets** for Sweden, we assume in both the base case and Scenario 1 that only targets that have already been agreed will be implemented. In Scenario 2, we assume further renewables expansion, in line with the so-called *planeringsram*, as discussed by Energimyndigheten.

Generation capacity in neighbouring countries is assumed to develop as follows:

- **Nuclear**: All German nuclear capacity is assumed to be shut down, while in Finland the reactor Olkiluoto 3 is assumed to be running by 2025.
- **Wind**: An expansion of wind capacity in Germany (+60%), Denmark (+43%) and Norway (+100%) in the base case scenario, based on Netzentwicklungsplan DE, Energinet.dk and Energimyndigheten. Slightly lower expansion in Scenario 1, and slightly higher expansion in Scenario 2.
- **Hydropower**: 5% higher generation capacity in Norway.

For **transmission capacities**, we assume a number of new connections will be in place by 2025, as detailed in Table A.1 below, based on the Danish Energy Agency. No variation across scenarios.

With respect to **hydrology**, we assume a 'normal year' in all scenarios, based on Svensk Energi's Elfakta.

Electricity demand is assumed to stay at the current level, without any variation across scenarios, based on Energimyndigheten.

For production capacities, in our base and market scenarios (Scenario 1), the nuclear power plants for which closure has been announced[73] are closed in 2025, leaving six reactors in operation with a total net capacity of 6,732 MW. In our non-market scenario (Scenario 2), all reactors save one have been closed in 2025. This leaves Sweden with a nuclear net capacity of 1,015 MW.

73 As of June 2016, these are Oskarshman 1 & 2, and Ringhals 1 & 2.

Table A.1 Scenario details

	Scenario 1 Return to market based decisions	Reference scenario Middle ground/base case	Scenario 2 Regulatory intervention and out-of-market decisions
Fuel prices *1	**Coal**: +37% **Natural gas**: +11%	**Coal**: +26% **Natural gas**: +2% **Biomass**: +8%	**Coal**: +2% **Natural gas**: -9%
ETS price *2	30 €/ton	20 €/ton	10 €/ton
Renewable energy targets		Fulfilling current renewable energy targets	Higher renewable energy targets in SE, in line with the 'planeringsram' *3
Generation capacities in neighbouring countries	**Wind**: 10% lower growth than base case in DE and DK	**Nuclear**: none in DE; +1 in FI **Wind**: DE +60%; DK +43%; NO +100% *4 **Hydro**: NO +5% *3	**Wind**: In DE, DK and NO: 10%. higher growth than scenario 2.
Transmission capacities *5		As today + DK-NL (700 MW), DK-DE: (700 MW), DK-UK (1400 MW), NO-DE: (1400 MW), NO-UK (1400 MW), SE-DE: (700 MW), DE-BE (1000 MW), Sydvästlänken 1200 MW + SE2 1200 MW	
Hydrology		Normal year	
Electricity demand		As today *3	

Source: Scenario 1 and 2 are both based on the reference scenario but varying according to the changes listed in the table

1. Coal and gas based on IEA WEO 2015. Biomass based on Energinet.dk
2. 10 €/ton is slightly above current forward prices. 20 €/ton is close to WEO figures (New Policies).
3. Energimyndigheten
4. Netzentwicklungsplan DE; Energinet.dk; Energimyndigheten
5. Energistyrelsen (DK)